Matador Resources Co
Form 10-Q
August 06, 2018
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2018

OR

¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission File Number 001-35410

Matador Resources Company
(Exact name of registrant as specified in its charter)

Texas (State or other jurisdiction of incorporation or organization)	27-4662601 (I.R.S. Employer Identification No.)
5400 LBJ Freeway, Suite 1500 Dallas, Texas	75240
(Address of principal executive offices)	(Zip Code)

(972) 371-5200
(Registrant’s telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. x Yes ¨ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). x Yes ¨ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company,” and “emerging growth company” in Rule 12b-2 of the Exchange Act.

Large accelerated filer x	Accelerated filer ¨
Non-accelerated filer ¨ (Do not check if a smaller reporting company)	Smaller reporting company ¨
	Emerging growth company ¨

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). ¨ Yes x No

As of August 1, 2018, there were 116,365,216 shares of the registrant’s common stock, par value $0.01 per share, outstanding.

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FOR THE QUARTER ENDED JUNE 30, 2018
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Part I — FINANCIAL INFORMATION
Item 1. Financial Statements — Unaudited
Matador Resources Company and Subsidiaries
CONDENSED CONSOLIDATED BALANCE SHEETS — UNAUDITED
(In thousands, except par value and share data)

	June 30, 2018	December 31, 2017
ASSETS		
Current assets		
Cash	$122,450	$96,505
Restricted cash	21,063	5,977
Accounts receivable		
Oil and natural gas revenues	74,771	65,962
Joint interest billings	71,041	67,225
Other	4,726	8,031
Derivative instruments	5,875	1,190
Lease and well equipment inventory	12,557	5,993
Prepaid expenses and other assets	8,454	6,287
Total current assets	320,937	257,170
Property and equipment, at cost		
Oil and natural gas properties, full-cost method		
Evaluated	3,338,515	3,004,770
Unproved and unevaluated	692,544	637,396
Midstream and other property and equipment	360,971	281,096
Less accumulated depletion, depreciation and amortization	(2,164,013)	(2,041,806)
Net property and equipment	2,228,017	1,881,456
Other assets	6,893	7,064
Total assets	$2,555,847	$2,145,690
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$25,278	$11,757
Accrued liabilities	133,365	174,348
Royalties payable	69,751	61,358
Amounts due to affiliates	8,108	10,302
Derivative instruments	4,016	16,429
Advances from joint interest owners	18,814	2,789
Amounts due to joint ventures	3,373	4,873
Other current liabilities	893	750
Total current liabilities	263,598	282,606
Long-term liabilities		
Senior unsecured notes payable	574,164	574,073
Asset retirement obligations	26,890	25,080
Derivative instruments	5,253	—
Other long-term liabilities	6,194	6,385
Total long-term liabilities	612,501	605,538
Commitments and contingencies (Note 9)		
Shareholders' equity		
Common stock - $0.01 par value, 160,000,000 shares authorized; 116,461,171 and 108,513,597 shares issued; and 116,357,739 and 108,510,160 shares outstanding,	1,165	1,085

respectively		
Additional paid-in capital	1,916,821	1,666,024
Accumulated deficit	(390,784)	(510,484)
Treasury stock, at cost, 103,432 and 3,437 shares, respectively	(2,670)	(69)
Total Matador Resources Company shareholders’ equity	1,524,532	1,156,556
Non-controlling interest in subsidiaries	155,216	100,990
Total shareholders’ equity	1,679,748	1,257,546
Total liabilities and shareholders’ equity	$2,555,847	$2,145,690

The accompanying notes are an integral part of these financial statements.
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Matador Resources Company and Subsidiaries
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS — UNAUDITED
(In thousands, except per share data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Revenues				
Oil and natural gas revenues	$209,019	$113,764	$390,973	$228,611
Third-party midstream services revenues	3,407	2,099	6,475	3,654
Realized (loss) gain on derivatives	(2,488)	558	(6,746)	(1,661)
Unrealized gain on derivatives	1,429	13,190	11,845	33,821
Total revenues	211,367	129,611	402,547	264,425
Expenses				
Production taxes, transportation and processing	20,110	12,875	37,901	24,682
Lease operating	25,006	16,040	47,154	31,797
Plant and other midstream services operating	5,676	2,942	9,896	5,283
Depletion, depreciation and amortization	66,838	41,274	122,207	75,266
Accretion of asset retirement obligations	375	314	739	614
General and administrative	19,369	17,177	37,295	33,515
Total expenses	137,374	90,622	255,192	171,157
Operating income	73,993	38,989	147,355	93,268
Other income (expense)				
Net gain on asset sales and inventory impairment	—	—	—	7
Interest expense	(8,004)	(9,224)	(16,495)	(17,679)
Other (expense) income	(352)	1,922	(299)	1,991
Total other expense	(8,356)	(7,302)	(16,794)	(15,681)
Net income	65,637	31,687	130,561	77,587
Net income attributable to non-controlling interest in subsidiaries	(5,831)	(3,178)	(10,861)	(5,094)
Net income attributable to Matador Resources Company shareholders	$59,806	$28,509	$119,700	$72,493
Earnings per common share				
Basic	$0.53	$0.28	$1.08	$0.72
Diluted	$0.53	$0.28	$1.08	$0.72
Weighted average common shares outstanding				
Basic	112,706	100,211	110,809	100,005
Diluted	113,056	100,227	111,280	100,455

The accompanying notes are an integral part of these financial statements.

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Matador Resources Company and Subsidiaries
CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY — UNAUDITED
(In thousands)
For the Six Months Ended June 30, 2018

	Common Stock		Additional paid-in capital	Accumulated deficit	Treasury Stock		Total shareholders' equity attributable to Matador Resources Company	Non-controlling interest in subsidiaries	Total shareholders' equity
	Shares	Amount			Shares	Amount			
Balance at January 1, 2018	108,514	$1,085	$1,666,024	$(510,484)	3	$(69)	$1,156,556	$100,990	$1,257,546
Issuance of common stock pursuant to employee stock compensation plan	717	7	(7)	—	—	—	—	—	—
Issuance of common stock	7,000	70	226,542	—	—	—	226,612	—	226,612
Cost to issue equity	—	—	(146)	—	—	—	(146)	—	(146)
Issuance of common stock pursuant to directors' and advisors' compensation plan	76	1	(1)	—	—	—	—	—	—
Stock-based compensation expense related to equity-based awards including amounts capitalized	—	—	11,327	—	—	—	11,327	—	11,327
Stock options exercised, net of options forfeited in net share settlements	154	2	(1,618)	—	—	—	(1,616)	—	(1,616)
Restricted stock forfeited	—	—	—	—	100	(2,601)	(2,601)	—	(2,601)
Contributions related to formation of Joint Venture (see Note 6)	—	—	14,700	—	—	—	14,700	—	14,700
Contributions from non-controlling interest owners of less-than-wholly-owned subsidiaries	—	—	—	—	—	—	—	53,900	53,900
Distributions to non-controlling interest owners of less-than-wholly-owned subsidiaries	—	—	—	—	—	—	—	(10,535)	(10,535)
Current period net income	—	—	—	119,700	—	—	119,700	10,861	130,561

Balance at June 30, 2018	116,461	$1,165	$1,916,821	$(390,784)	103	$(2,670)	$1,524,532	$155,216	$1,679,748

The accompanying notes are an integral part of these financial statements.

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Matador Resources Company and Subsidiaries
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS — UNAUDITED
(In thousands)

	Six Months Ended June 30, 2018	2017
Operating activities		
Net income	$130,561	$77,587
Adjustments to reconcile net income to net cash provided by operating activities		
Unrealized gain on derivatives	(11,845)	(33,821)
Depletion, depreciation and amortization	122,207	75,266
Accretion of asset retirement obligations	739	614
Stock-based compensation expense	8,945	11,192
Amortization of debt issuance cost	411	64
Net gain on asset sales and inventory impairment	—	(7)
Changes in operating assets and liabilities		
Accounts receivable	(9,321)	(25,642)
Lease and well equipment inventory	(8,611)	(140)
Prepaid expenses	(2,167)	(2,619)
Other assets	(149)	165
Accounts payable, accrued liabilities and other current liabilities	(883)	4,442
Royalties payable	8,393	11,435
Advances from joint interest owners	16,025	3,768
Other long-term liabilities	(97)	(1,062)
Net cash provided by operating activities	254,208	121,242
Investing activities		
Oil and natural gas properties capital expenditures	(421,595)	(328,929)
Expenditures for midstream and other property and equipment	(79,560)	(41,743)
Proceeds from sale of assets	7,593	977
Net cash used in investing activities	(493,562)	(369,695)
Financing activities		
Repayments of borrowings	(45,000)	—
Borrowings under Credit Agreement	45,000	—
Proceeds from issuance of common stock	226,612	—
Cost to issue equity	(73)	—
Proceeds from stock options exercised	464	2,201
Contributions related to formation of Joint Venture	14,700	171,500
Contributions from non-controlling interest owners of less-than-wholly-owned subsidiaries	53,900	14,700
Distributions to non-controlling interest owners of less-than-wholly-owned subsidiaries	(10,535)	(1,960)
Taxes paid related to net share settlement of stock-based compensation	(4,683)	(2,970)
Purchase of non-controlling interest of less-than-wholly-owned subsidiary	—	(2,653)
Net cash provided by financing activities	280,385	180,818
Increase (decrease) in cash and restricted cash	41,031	(67,635)
Cash and restricted cash at beginning of period	102,482	214,142
Cash and restricted cash at end of period	$143,513	$146,507

Supplemental disclosures of cash flow information (Note 10)

The accompanying notes are an integral part of these financial statements.

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Matador Resources Company and Subsidiaries

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — UNAUDITED

NOTE 1 — NATURE OF OPERATIONS

Matador Resources Company, a Texas corporation ("Matador" and, collectively with its subsidiaries, the "Company"), is an independent energy company engaged in the exploration, development, production and acquisition of oil and natural gas resources in the United States, with an emphasis on oil and natural gas shale and other unconventional plays. The Company's current operations are focused primarily on the oil and liquids-rich portion of the Wolfcamp and Bone Spring plays in the Delaware Basin in Southeast New Mexico and West Texas. The Company also operates in the Eagle Ford shale play in South Texas and the Haynesville shale and Cotton Valley plays in Northwest Louisiana and East Texas. Additionally, the Company conducts midstream operations, primarily through its midstream joint venture, San Mateo Midstream, LLC ("San Mateo" or the "Joint Venture"), in support of the Company's exploration, development and production operations and provides natural gas processing, oil transportation services, oil, natural gas and salt water gathering services and salt water disposal services to third parties.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Interim Financial Statements, Basis of Presentation, Consolidation and Significant Estimates

The interim unaudited condensed consolidated financial statements of the Company have been prepared in accordance with the rules and regulations of the Securities and Exchange Commission ("SEC") but do not include all of the information and footnotes required by generally accepted accounting principles in the United States of America ("U.S. GAAP") for complete financial statements and should be read in conjunction with the Company's audited consolidated financial statements and notes thereto included in the Company's Annual Report on Form 10-K for the year ended December 31, 2017 (the "Annual Report") filed with the SEC. The Company consolidates certain subsidiaries and joint ventures that are less than wholly-owned and are not involved in oil and natural gas exploration, including San Mateo, and the net income and equity attributable to the non-controlling interest in these subsidiaries have been reported separately as required by Accounting Standards Codification, Consolidation (Topic 810). The Company proportionately consolidates certain joint ventures that are less than wholly-owned and are involved in oil and natural gas exploration. All intercompany accounts and transactions have been eliminated in consolidation. In management's opinion, these interim unaudited condensed consolidated financial statements include all normal, recurring adjustments that are necessary for a fair presentation of the Company's interim unaudited condensed consolidated financial statements as of June 30, 2018. Amounts as of December 31, 2017 are derived from the Company's audited consolidated financial statements included in the Annual Report.

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates and assumptions may also affect disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The Company's interim unaudited condensed consolidated financial statements are based on a number of significant estimates, including accruals for oil and natural gas revenues, accrued assets and liabilities primarily related to oil and natural gas and midstream operations, stock-based compensation, valuation of derivative instruments and oil and natural gas reserves. The estimates of oil and natural gas reserves quantities and future net cash flows are the basis for the calculations of depletion and impairment of oil and natural gas properties, as well as estimates of asset retirement obligations and certain tax accruals. While the Company believes its estimates are reasonable, changes in facts and assumptions or the discovery of new information may result in revised estimates. Actual results could differ from these estimates.

Change in Accounting Principles

During the first quarter of 2018, the Company adopted Accounting Standards Codification, Revenue from Contracts with Customers (Topic 606) ("ASC 606"), which specifies how and when to recognize revenue. This standard requires expanded disclosures surrounding revenue recognition and is intended to improve, and converge with international standards, the financial reporting requirements for revenue from contracts with customers. The Company adopted the new guidance using the modified retrospective approach. The adoption did not require an adjustment to opening accumulated deficit for any cumulative effect adjustment and did not have a material impact on the Company's

consolidated balance sheets, statements of operations, statement of shareholders' equity or statements of cash flows.
Prior to the adoption of ASC 606, the Company recorded oil and natural gas revenues at the time of physical transfer of such products to the purchaser. The Company followed the sales method of accounting for oil and natural gas sales, recognizing revenues based on the Company's actual proceeds from the oil and natural gas sold to purchasers.
The Company enters into contracts with customers to sell its oil and natural gas production. With the adoption of ASC 606, revenue on these contracts is recognized in accordance with the five-step revenue recognition model prescribed in

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

ASC 606. Specifically, revenue is recognized when the Company's performance obligations under these contracts are satisfied, which generally occurs with the transfer of control of the oil and natural gas to the purchaser. Control is generally considered transferred when the following criteria are met: (i) transfer of physical custody, (ii) transfer of title, (iii) transfer of risk of loss and (iv) relinquishment of any repurchase rights or other similar rights. Given the nature of the products sold, revenue is recognized at a point in time based on the amount of consideration the Company expects to receive in accordance with the price specified in the contract. Consideration under the oil and natural gas marketing contracts is typically received from the purchaser one to two months after production.

The majority of the Company's oil marketing contracts transfer physical custody and title at or near the wellhead, which is generally when control of the oil has been transferred to the purchaser. The majority of the oil produced is sold under contracts using market-based pricing, which price is then adjusted for differentials based upon delivery location and oil quality. To the extent the differentials are incurred at or after the transfer of control of the oil, the differentials are included in oil sales on the statements of operations as they represent part of the transaction price of the contract. If the differentials, or other related costs, are incurred prior to the transfer of control of the oil, those costs are included in production taxes, transportation and processing expenses on the Company's consolidated statements of operations, as they represent payment for services performed outside of the contract with the customer.

The Company's natural gas is sold at the lease location, at the inlet or outlet of a natural gas plant or at an interconnect near a marketing hub following transportation from a processing plant. The majority of the Company's natural gas is sold under fee-based contracts. When the natural gas is sold at the lease, the purchaser gathers the natural gas and transports the natural gas via pipeline to natural gas processing plants where, if necessary, natural gas liquid ("NGL") products are extracted. The NGL products and remaining residue gas are then sold by the purchaser, or if the Company elects to repurchase the natural gas, the Company sells the natural gas to a third party. Under the fee-based contracts, the Company receives NGL and residue gas value, less the fee component, or is invoiced the fee component. To the extent control of the natural gas transfers upstream of the transportation and processing activities, revenue is recognized as the net amount received from the purchaser. To the extent that control transfers downstream of those services, revenue is recognized on a gross basis, and the related costs are included in production taxes, transportation and processing expenses on the Company's consolidated statements of operations.

The Company recognizes midstream services revenues at the time services have been rendered and the price is fixed and determinable. Third-party midstream services revenues are those revenues from midstream operations related to third parties, including working interest owners in our operated wells. All midstream services revenues related to the Company's working interest are eliminated in consolidation. Since the Company has a right to payment from its customers in amounts that correspond directly to the value that the customer receives from the performance completed on each contract, the Company applies the practical expedient in ASC 606 that allows recognition of revenue in the amount for which there is a right to invoice the customer without estimating a transaction price for each contract and allocating that transaction price to the performance obligations within each contract.

The Company determined the impact to its consolidated financial statements as a result of adoption of ASC 606 was a \$2.6 million and \$4.8 million decrease in oil and natural gas revenues and a \$2.6 million and \$4.8 million decrease in production taxes, transportation and processing expenses for the three and six months ended June 30, 2018, respectively, which was not material. As a result of adoption of this standard, the Company is now required to disclose the following information regarding total revenues and revenues from contracts with customers on a disaggregated basis for the three and six months ended June 30, 2018 (in thousands).

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Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — UNAUDITED — CONTINUED

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

	Three Months Ended June 30, 2018	Six Months Ended June 30, 2018
Revenues from contracts with customers	$212,426	$397,448
Realized loss on derivatives	(2,488)	(6,746)
Unrealized gain on derivatives	1,429	11,845
Total revenues	$211,367	$402,547

	Three Months Ended June 30, 2018	Six Months Ended June 30, 2018
Oil revenues	$166,271	$314,430
Natural gas revenues	42,748	76,543
Third-party midstream services revenues	3,407	6,475
Total revenues from contracts with customers	$212,426	$397,448

The Company does not disclose the value of unsatisfied performance obligations under its contracts with customers as it applies the practical expedient in accordance with ASC 606. The expedient, as described in ASC 606-10-50-14(a), applies to variable consideration that is recognized as control of the product is transferred to the customer. Since each unit of product represents a separate performance obligation, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

During the first quarter of 2018, the Company adopted Accounting Standards Update ("ASU") 2016-18, Statement of Cash Flows (Topic 230), which specifies that a statement of cash flows explain the change during the period in the total of cash, cash equivalents and amounts generally described as restricted cash or restricted cash equivalents. The Company adopted ASU 2016-18 effective January 1, 2018 and determined that the adoption of this ASU changed the presentation of its beginning and ending cash balances and eliminated the presentation of changes in restricted cash balances from investing activities in its consolidated statements of cash flows. The Company adopted the new guidance using the retrospective transition method; as a result, approximately $6.0 million and $1.3 million of restricted cash was added to the beginning cash balance for the six months ended June 30, 2018 and 2017, respectively.

During the first quarter of 2018, the Company adopted ASU 2017-01, Business Combinations (Topic 805), which specifies the minimum inputs and processes required for an integrated set of assets and activities to meet the definition of a business. The Company adopted ASU 2017-01 prospectively, which did not have a material impact on its consolidated financial statements.

Property and Equipment

The Company uses the full-cost method of accounting for its investments in oil and natural gas properties. Under this method, the Company is required to perform a ceiling test each quarter that determines a limit, or ceiling, on the capitalized costs of oil and natural gas properties based primarily on the after-tax estimated future net cash flows from oil and natural gas properties using a 10% discount rate and the arithmetic average of first-day-of-the-month oil and natural gas prices for the prior 12-month period. For both the three and six months ended June 30, 2018 and 2017, the cost center ceiling was higher than the capitalized costs of oil and natural gas properties, and, as a result, no

impairment charge was necessary.
The Company capitalized approximately $6.8 million and $5.2 million of its general and administrative costs for the three months ended June 30, 2018 and 2017, respectively, and approximately $2.6 million and $1.9 million of its interest expense for the three months ended June 30, 2018 and 2017, respectively. The Company capitalized approximately $14.1 million and $10.8 million of its general and administrative costs for the six months ended June 30, 2018 and 2017, respectively, and approximately $4.5 million and $3.2 million of its interest expense for the six months ended June 30, 2018 and 2017, respectively.
Earnings (Loss) Per Common Share
The Company reports basic earnings attributable to Matador Resources Company shareholders per common share, which excludes the effect of potentially dilutive securities, and diluted earnings attributable to Matador Resources Company

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Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — UNAUDITED — CONTINUED

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

shareholders per common share, which includes the effect of all potentially dilutive securities unless their impact is anti-dilutive.
The following table sets forth the computation of diluted weighted average common shares outstanding for the three and six months ended June 30, 2018 and 2017 (in thousands).

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Weighted average common shares outstanding				
Basic	112,706	100,211	110,809	100,005
Dilutive effect of options and restricted stock units	350	16	471	450
Diluted weighted average common shares outstanding	113,056	100,227	111,280	100,455

Recent Accounting Pronouncements
Leases. In February 2016, the Financial Accounting Standards Board ("FASB") issued ASU 2016-02, Leases (Topic 842), which requires the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases under previous U.S. GAAP. This ASU will become effective for fiscal years beginning after December 15, 2018 with early adoption permitted. Entities are required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. The modified retrospective approach includes a number of optional practical expedients that entities may elect to apply. These practical expedients relate to the identification and classification of leases that commenced before the effective date, initial direct costs for leases that commenced before the effective date and the ability to use hindsight in evaluating lessee options to extend or terminate a lease or to purchase the underlying asset. In January 2018, the FASB issued ASU 2018-01, Leases (Topic 842), which is a land easement practical expedient. If the Company elects to use this practical expedient, the Company should evaluate new or modified land easements under this ASU beginning at the date of adoption. Adoption of ASU 2016-02 will result in increased reported assets and liabilities. The quantitative impact of the new lease standard will depend on the leases in force at the time of adoption. The Company is currently evaluating the impact of the adoption of these ASUs on its consolidated financial statements, including identifying all leases, as defined under the new lease standard, determining which practical expedients the Company will use and quantifying the impact of the new lease standard on existing leases. The Company expects to adopt these ASUs as of January 1, 2019.
Stock Compensation. In June 2018, the FASB issued ASU 2018-07, Compensation - Stock Compensation (Topic 718): Improvements to Nonemployee Share-Based Payment Accounting. This ASU extends the scope of Topic 718 to include share-based payment transactions related to the acquisition of goods and services from nonemployees. Currently, the Company accounts for stock-based awards to special advisors and contractors under ASC 505-50 as liability instruments, and the fair value of the awards is recalculated each reporting period. Upon adoption, all such awards will be measured at fair value on the grant date and the resulting expense will be recognized on a straight-line basis over the awards' vesting period. This ASU is effective for fiscal years beginning after December 15, 2018 with early adoption permitted. The transitional guidance requires entities to remeasure all unvested awards that are being accounted for under ASC 505-50 as liability instruments as of the beginning of the year in which this ASU is adopted. The Company expects to adopt this ASU as of January 1, 2019 and does not anticipate this ASU will have a material impact to the Company's consolidated financial statements.

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Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — UNAUDITED — CONTINUED

NOTE 3 — ASSET RETIREMENT OBLIGATIONS

The following table summarizes the changes in the Company's asset retirement obligations for the six months ended June 30, 2018 (in thousands).

Beginning asset retirement obligations	$26,256
Liabilities incurred during period	1,589
Liabilities settled during period	(459)
Accretion expense	739
Ending asset retirement obligations	28,125
Less: current asset retirement obligations[1]	(1,235)
Long-term asset retirement obligations	$26,890

(1) Included in accrued liabilities in the Company's interim unaudited condensed consolidated balance sheet at June 30, 2018.

NOTE 4 — DEBT

At June 30, 2018 and August 1, 2018, the Company had $575.0 million of outstanding 6.875% senior notes due 2023 (the "Notes"), no borrowings outstanding under the Company's revolving credit agreement (the "Credit Agreement") and approximately $3.0 million in outstanding letters of credit issued pursuant to the Credit Agreement.

Credit Agreement

The borrowing base under the Credit Agreement is determined semi-annually as of May 1 and November 1 by the lenders based primarily on the estimated value of the Company's proved oil and natural gas reserves at December 31 and June 30 of each year, respectively. Both the Company and the lenders may request an unscheduled redetermination of the borrowing base once each between scheduled redetermination dates. During the first quarter of 2018, the lenders completed their review of the Company's proved oil and natural gas reserves at December 31, 2017, and as a result, on March 5, 2018, the borrowing base was increased to $725.0 million. This March 2018 redetermination constituted the regularly scheduled May 1 redetermination. The Company elected to keep the borrowing commitment at $400.0 million and the maximum facility amount remained at $500.0 million. Borrowings under the Credit Agreement are limited to the lowest of the borrowing base, the maximum facility amount and the elected commitment. The Credit Agreement matures on October 16, 2020.

The Company believes that it was in compliance with the terms of the Credit Agreement at June 30, 2018.

Senior Unsecured Notes

On April 14, 2015 and December 9, 2016, the Company issued $400.0 million and $175.0 million, respectively, of Notes. The Notes mature on April 15, 2023, and interest is payable semi-annually in arrears on April 15 and October 15 of each year.

NOTE 5 — INCOME TAXES

The Company's deferred tax assets exceeded its deferred tax liabilities at June 30, 2018 due to the deferred tax assets generated by full-cost ceiling impairment charges recorded in prior periods. The Company established a valuation allowance against most of the deferred tax assets beginning in the third quarter of 2015 and retained a full valuation allowance at June 30, 2018 due to uncertainties regarding the future realization of its deferred tax assets. The valuation allowance will continue to be recognized until the realization of future deferred tax benefits is more likely than not to be utilized.

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NOTE 6 — EQUITY

Equity Offering
On May 17, 2018, the Company completed a public offering of 7,000,000 shares of its common stock. After deducting offering costs totaling approximately $0.1 million, the Company received net proceeds of approximately $226.5 million. The proceeds from this offering were and are being used to acquire additional leasehold and mineral acres in the Delaware Basin, to fund certain midstream initiatives in the Delaware Basin and for general corporate purposes, including to fund a portion of the Company’s future capital expenditures. Pending such uses, the Company used a portion of the proceeds from the offering to repay the $45.0 million of outstanding borrowings under the Credit Agreement and invested the remaining funds in short-term marketable securities.

Stock-based Compensation
In February 2018, the Company granted awards of 667,488 shares of restricted stock and options to purchase 563,408 shares of the Company’s common stock at an exercise price of $29.68 per share to certain of its employees. The fair value of these awards was approximately $26.9 million. All of these awards vest ratably over three years.

Performance Incentive
In connection with the formation of San Mateo in 2017, the Company has the ability to earn a total of $73.5 million in performance incentives to be paid by its joint venture partner, a subsidiary of Five Point Energy LLC (“Five Point”), over a five-year period. The Company earned, and Five Point paid to the Company, $14.7 million in performance incentives during the six months ended June 30, 2018, and the Company may earn an additional $58.8 million in performance incentives over the next four years. These performance incentives are recorded as an increase to additional paid-in capital when received.

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NOTE 7 — DERIVATIVE FINANCIAL INSTRUMENTS

At June 30, 2018, the Company had various costless collar, three-way costless collar and swap contracts open and in place to mitigate its exposure to oil and natural gas price volatility, each with a specific term (calculation period), notional quantity (volume hedged) and price floor and ceiling and fixed price for the swaps. Each contract is set to expire at varying times during 2018 and 2019.
The following is a summary of the Company's open costless collar contracts for oil and natural gas at June 30, 2018.

Commodity	Calculation Period	Notional Quantity (Bbl or MMBtu)	Weighted Average Price Floor ($/Bbl or $/MMBtu)	Weighted Average Price Ceiling ($/Bbl or $/MMBtu)	Fair Value of Asset (Liability) (thousands)
Oil - WTI(1)	07/01/2018 - 12/31/2018	1,440,000	$ 44.27	$ 60.29	$ (15,986)
Oil - WTI(1)	01/01/2019 - 12/31/2019	2,400,000	$ 50.00	$ 64.75	(12,208)
Oil - LLS(2)	07/01/2018 - 12/31/2018	360,000	$ 45.00	$ 63.05	(4,381)
Natural Gas	07/01/2018 - 12/31/2018	8,400,000	$ 2.58	$ 3.67	79
Total open costless collar contracts					$ (32,496)

(1) NYMEX West Texas Intermediate crude oil.
(2) Argus Louisiana Light Sweet crude oil.

The following is a summary of the Company's open three-way costless collar contracts for oil at June 30, 2018. Open three-way costless collars consist of a long put (the floor), a short call (the ceiling) and a long call that limits losses on the upside.

Commodity	Calculation Period	Notional Quantity (Bbl)	Weighted Average Price Floor ($/Bbl)	Weighted Average Price, Short Call ($/Bbl)	Weighted Average Price, Long Call ($/Bbl)	Fair Value of Asset (Liability) (thousands)
Oil - WTI(1)	07/01/2018 - 12/31/2018	960,000	$ 50.08	$ 63.50	$ 66.68	$ (2,249)
Total open three-way costless collar contracts						$ (2,249)

(1) NYMEX West Texas Intermediate crude oil.

The following is a summary of the Company's open basis swap contracts for oil at June 30, 2018.

Commodity	Calculation Period	Notional Quantity (Bbl)	Fixed Price ($/Bbl)	Fair Value of Asset (Liability) (thousands)
Oil Basis Swaps	07/01/2018 - 12/31/2018	2,610,000	$(1.02)	$ 31,351
Total open swap contracts				$ 31,351
Total open derivative financial instruments				$ (3,394)

The Company's derivative financial instruments are subject to master netting arrangements, and all but one counterparty allow for cross-commodity master netting provided the settlement dates for the commodities are the same. The Company does not present different types of commodities with the same counterparty on a net basis in its interim unaudited condensed consolidated balance sheets.

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NOTE 7 — DERIVATIVE FINANCIAL INSTRUMENTS — Continued

The following table presents the gross asset and liability fair values of the Company's commodity price derivative financial instruments and the location of these balances in the interim unaudited condensed consolidated balance sheets as of June 30, 2018 and December 31, 2017 (in thousands).

Derivative Instruments	Gross amounts recognized	Gross amounts netted in the condensed consolidated balance sheets	Net amounts presented in the condensed consolidated balance sheets
June 30, 2018			
Current assets	$101,679	$ (95,804)	$ 5,875
Other assets	2,749	(2,749)	—
Current liabilities	(99,820)	95,804	(4,016)
Other liabilities	(8,002)	2,749	(5,253)
Total	$(3,394)	$ —	$ (3,394)
December 31, 2017			
Current assets	$131,092	$ (129,902)	$ 1,190
Current liabilities	(146,331)	129,902	(16,429)
Total	$(15,239)	$ —	$ (15,239)

The following table summarizes the location and aggregate fair value of all derivative financial instruments recorded in the interim unaudited condensed consolidated statements of operations for the periods presented (in thousands). These derivative financial instruments are not designated as hedging instruments.

Type of Instrument	Location in Condensed Consolidated Statement of Operations	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
Derivative Instrument					
Oil	Revenues: Realized (loss) gain on derivatives	$(2,488)	$581	$(6,797)	$(1,053)
Natural Gas	Revenues: Realized (loss) gain on derivatives	—	(23)	51	(608)
Realized (loss) gain on derivatives		(2,488)	558	(6,746)	(1,661)
Oil	Revenues: Unrealized gain on derivatives	1,829	10,643	12,956	28,422
Natural Gas	Revenues: Unrealized (loss) gain on derivatives	(400)	2,547	(1,111)	5,399
Unrealized gain on derivatives		1,429	13,190	11,845	33,821
Total		$(1,059)	$13,748	$5,099	$32,160

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Matador Resources Company and Subsidiaries
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — UNAUDITED — CONTINUED

NOTE 8 — FAIR VALUE MEASUREMENTS

The Company measures and reports certain financial and non-financial assets and liabilities on a fair value basis. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). Fair value measurements are classified and disclosed in one of the following categories.

Level 1	Unadjusted quoted prices for identical, unrestricted assets or liabilities in active markets.
Level 2	Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that are valued with industry standard models that consider various inputs, including: (i) quoted forward prices for commodities, (ii) time value of money and (iii) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument and can be derived from observable data or supported by observable levels at which transactions are executed in the marketplace.
Level 3	Unobservable inputs that are not corroborated by market data that reflect a company's own market assumptions.

Financial and non-financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment, which may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

The following tables summarize the valuation of the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis in accordance with the classifications provided above as of June 30, 2018 and December 31, 2017 (in thousands).

	Fair Value Measurements at June 30, 2018 using			
Description	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Natural gas derivatives	$—	$79	$—	$79
Oil derivatives and basis swaps	—	(3,473)	—	(3,473)
Total	$—	$(3,394)	$—	$(3,394)

	Fair Value Measurements at December 31, 2017 using			
Description	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Natural gas derivatives	$—	$1,190	$—	$1,190
Oil derivatives and basis swaps	—	(16,429)	—	(16,429)
Total	$—	$(15,239)	$—	$(15,239)

Additional disclosures related to derivative financial instruments are provided in Note 7.

Other Fair Value Measurements

At June 30, 2018 and December 31, 2017, the carrying values reported on the interim unaudited condensed consolidated balance sheets for accounts receivable, prepaid expenses and other assets, accounts payable, accrued liabilities, royalties payable, amounts due to affiliates, advances from joint interest owners, amounts due to joint ventures and other current liabilities approximated their fair values due to their short-term maturities.

At June 30, 2018 and December 31, 2017, the fair value of the Notes was $603.4 million and $614.1 million, respectively, based on quoted market prices, which represent Level 1 inputs in the fair value hierarchy.

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NOTE 9 — COMMITMENTS AND CONTINGENCIES

Processing, Transportation and Salt Water Disposal Commitments

Delaware Basin — Loving County, Texas Natural Gas Processing

In late 2015, the Company entered into a 15-year, fixed-fee natural gas gathering and processing agreement whereby the Company committed to deliver the anticipated natural gas production from a significant portion of its Loving County, Texas acreage in West Texas through the counterparty’s gathering system for processing at the counterparty’s facilities. Under this agreement, if the Company does not meet the volume commitment for transportation and processing at the facilities in a contract year, it will be required to pay a deficiency fee per MMBtu of natural gas deficiency. At the end of each year of the agreement, the Company can elect to have the previous year’s actual transportation and processing volumes be the new minimum commitment for each of the remaining years of the contract. As such, the Company has the ability to unilaterally reduce the gathering and processing commitment if the Company’s production in the Loving County area is less than the Company’s minimum commitment. If the Company ceased operations in this area at June 30, 2018, the total deficiency fee required to be paid would be approximately $10.9 million. In addition, if the Company elects to reduce the gathering and processing commitment in any year, the Company has the ability to elect to increase the committed volumes in any future year to the originally agreed gathering and processing commitment. Any quantity in excess of the volume commitment delivered in a contract year can be carried over to the next contract year for purposes of calculating that year’s natural gas deficiency. The Company paid approximately $4.0 million and $3.7 million in natural gas processing and gathering fees under this agreement during the three months ended June 30, 2018 and 2017, respectively, and $7.4 million and $6.8 million in natural gas processing and gathering fees under this agreement during the six months ended June 30, 2018 and 2017, respectively. The Company can elect to either sell the residue gas to the counterparty at the tailgate of its processing plants or have the counterparty deliver to the Company the residue gas in-kind to be sold to third parties downstream of the plants.

Delaware Basin — Eddy County, New Mexico Natural Gas Transportation

In late 2017, the Company entered into an 18-year, fixed-fee natural gas transportation agreement whereby the Company committed to deliver a portion of the residue natural gas production at the tailgate of San Mateo’s Black River cryogenic natural gas processing plant in the Rustler Breaks asset area (the “Black River Processing Plant”) to transport through the counterparty’s pipeline. Under this agreement, if the Company does not meet the volume commitment for transportation in a contract year, the Company will owe the fees to transport the committed volume whether or not the committed volume is utilized. The minimum contractual obligation at June 30, 2018 was approximately $45.8 million. The Company paid approximately $0.9 million and $1.5 million in transportation fees under this agreement during the three and six months ended June 30, 2018, respectively.

In late 2017, the Company also entered into a fixed-fee NGL transportation and fractionation agreement whereby the Company committed to deliver its NGL production at the tailgate of the Black River Processing Plant. The Company is committed to deliver a minimum amount of NGLs to the counterparty upon construction and completion of a pipeline expansion and a fractionation facility by the counterparty, which is currently expected to be completed late in 2019. The Company has no rights to compel the counterparty to construct this pipeline extension or fractionation facility. If the counterparty does not construct the pipeline extension and fractionation facility, then the Company does not have any minimum volume commitments under the agreement. If the counterparty constructs the pipeline extension and fractionation facility on or prior to February 28, 2021, then the Company will have a commitment to deliver a minimum amount of NGLs for seven years following the completion of the pipeline extension and fractionation facility. If the Company does not meet its NGL volume commitment in any quarter during the seven-year commitment period, it will be required to pay a deficiency fee per gallon of NGL deficiency. Should the pipeline extension and fractionation facility be completed on or prior to February 28, 2021, the minimum contractual obligation during the seven-year period would be approximately $132.3 million.

In April 2018, the Company entered into a short-term natural gas transportation agreement whereby the Company committed to deliver a portion of the residue natural gas production at the tailgate of the Black River Processing Plant to transport through the counterparty's pipeline. Under this short-term agreement, the Company will owe the fees to transport the committed volume whether or not the committed volume is transported through the counterparty's pipeline. The minimum contractual obligation under this short-term contract at June 30, 2018 is approximately $4.6 million. This short-term agreement ends on September 30, 2019. The Company paid approximately $0.2 million in transportation fees under this agreement during the three and six months ended June 30, 2018.

In addition, in April 2018, the Company entered into a 16-year, fixed-fee natural gas transportation agreement that begins on October 1, 2019, whereby the Company committed to deliver a portion of the residue natural gas production at the tailgate of the Black River Processing Plant to transport through the counterparty's pipeline. The Company will owe the fees to transport

NOTE 9 — COMMITMENTS AND CONTINGENCIES — Continued

the committed volume whether or not the committed volume is transported through the counterparty's pipeline. The minimum contractual obligation at June 30, 2018 was approximately $56.8 million.

In May 2018, the Company also entered into a 10-year, fixed-fee natural gas sales agreement whereby the Company committed to deliver residue natural gas through the counterparty's pipeline to the Texas Gulf Coast beginning on the in-service date of such pipeline, which is expected to be operational in late 2019. If the Company does not meet the volume commitment specified in the natural gas sales agreement, it may be required to pay a deficiency fee per MMBtu of natural gas deficiency. The minimum contractual obligation at June 30, 2018 was approximately $200.6 million.

Delaware Basin — San Mateo

In February 2017, the Company dedicated its current and future leasehold interests in the Rustler Breaks and Wolf asset areas pursuant to 15-year, fixed-fee natural gas, oil and salt water gathering agreements and salt water disposal agreements. In addition, the Company dedicated its current and future leasehold interests in the Rustler Breaks asset area pursuant to a 15-year, fixed-fee natural gas processing agreement (collectively with the gathering and salt water disposal agreements, the "Operational Agreements"). San Mateo provides the Company with firm service under each of the Operational Agreements in exchange for certain minimum volume commitments. The minimum contractual obligation under the Operational Agreements at June 30, 2018 was approximately $222.6 million.

Beginning in May 2017, a subsidiary of San Mateo entered into certain agreements with third parties for the engineering, procurement, construction and installation of an expansion of the Black River Processing Plant. The expansion was completed late in the first quarter of 2018. San Mateo's total commitments under these agreements are $55.3 million. The subsidiary of San Mateo paid approximately $1.1 million and $3.6 million under these agreements during the three and six months ended June 30, 2018. As of June 30, 2018, the remaining obligations under these agreements were $2.0 million, which are expected to be paid within the next few months.

During the first quarter of 2018, a subsidiary of San Mateo entered into agreements for additional field compression and an amine gas treatment unit to maximize the operation of the Black River Processing Plant. San Mateo's total commitments under these agreements are $19.9 million. The subsidiary of San Mateo paid approximately $6.0 million and $6.5 million under these agreements during the three and six months ended June 30, 2018. As of June 30, 2018, the remaining obligations under these agreements were $13.5 million, which are expected to be paid within the next year.

Other Commitments

The Company does not own or operate its own drilling rigs, but instead enters into contracts with third parties for such drilling rigs. These contracts establish daily rates for the drilling rigs and the term of the Company's commitment for the drilling services to be provided. The Company would incur a termination obligation if the Company elected to terminate a contract and if the drilling contractor were unable to secure replacement work for the contracted drilling rigs at the same daily rates being charged to the Company prior to the end of their respective contract terms. The Company's undiscounted minimum outstanding aggregate termination obligations under its drilling rig contracts were approximately $32.4 million at June 30, 2018.

At June 30, 2018, the Company had outstanding commitments to participate in the drilling and completion of various non-operated wells. If all of these wells are drilled and completed as proposed, the Company's minimum outstanding aggregate commitments for its participation in these non-operated wells were approximately $47.2 million at June 30, 2018. The Company expects these costs to be incurred within the next year.

Legal Proceedings

The Company is a party to several lawsuits encountered in the ordinary course of its business. While the ultimate outcome and impact to the Company cannot be predicted with certainty, in the opinion of management, it is remote that these lawsuits will have a material adverse impact on the Company's financial condition, results of operations or cash flows.

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NOTE 10 — SUPPLEMENTAL DISCLOSURES

Accrued Liabilities
The following table summarizes the Company's current accrued liabilities at June 30, 2018 and December 31, 2017 (in thousands).

	June 30, 2018	December 31, 2017
Accrued evaluated and unproved and unevaluated property costs	$79,540	$ 105,347
Accrued midstream property costs	11,459	14,823
Accrued cost to issue equity	73	—
Accrued lease operating expenses	14,209	12,611
Accrued interest on debt	8,345	8,345
Accrued asset retirement obligations	1,235	1,176
Accrued partners' share of joint interest charges	14,824	27,628
Other	3,680	4,418
Total accrued liabilities	$133,365	$ 174,348

Supplemental Cash Flow Information
The following table provides supplemental disclosures of cash flow information for the six months ended June 30, 2018 and 2017 (in thousands).

	Six Months Ended June 30,	
	2018	2017
Cash paid for interest expense, net of amounts capitalized	$14,286	$15,875
Increase in asset retirement obligations related to mineral properties	$834	$1,978
Increase (decrease) in asset retirement obligations related to midstream properties	$296	$(138)
(Decrease) increase in liabilities for oil and natural gas properties capital expenditures	$(26,389)	$43,797
(Decrease) increase in liabilities for midstream properties capital expenditures	$(2,371)	$1,838
Stock-based compensation expense recognized as liability	$(93)	$(339)
Increase (decrease) in liabilities for accrued cost to issue equity	$73	$(343)
Transfer of inventory from (to) oil and natural gas properties	$343	$(228)
Transfer of inventory to midstream and other property and equipment	$(2,390)	$—

The following table provides a reconciliation of cash and restricted cash recorded in the interim unaudited condensed consolidated balance sheets to cash and restricted cash as presented on the interim unaudited condensed consolidated statements of cash flows (in thousands).

	Six Months Ended June 30,	
	2018	2017
Cash	$122,450	$131,467
Restricted cash	21,063	15,040
Total cash and restricted cash	$143,513	$146,507

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NOTE 11 — SEGMENT INFORMATION

The Company operates in two business segments: (i) exploration and production and (ii) midstream. The exploration and production segment is engaged in the acquisition, exploration, development and production of oil and natural gas properties and is currently focused primarily on the oil and liquids-rich portion of the Wolfcamp and Bone Spring plays in the Delaware Basin in Southeast New Mexico and West Texas. The Company also operates in the Eagle Ford shale play in South Texas and the Haynesville shale and Cotton Valley plays in Northwest Louisiana and East Texas. The midstream segment conducts midstream operations in support of the Company's exploration, development and production operations and provides natural gas processing, oil transportation services, natural gas, oil and salt water gathering services and salt water disposal services to third parties. Substantially all of the Company's midstream operations in the Rustler Breaks and Wolf asset areas in the Delaware Basin are conducted through San Mateo.
The following tables present selected financial information for the periods presented regarding the Company's business segments on a stand-alone basis, corporate expenses that are not allocated to a segment and the consolidation and elimination entries necessary to arrive at the financial information for the Company on a consolidated basis (in thousands). On a consolidated basis, midstream services revenues consist primarily of those revenues from midstream operations related to third parties, including working interest owners in the Company's operated wells. All midstream services revenues associated with Company-owned production are eliminated in consolidation. In evaluating the operating results of the exploration and production and midstream segments, the Company does not allocate certain expenses to the individual segments, including general and administrative expenses. Such expenses are reflected in the column labeled "Corporate."

	Exploration and Production	Midstream	Corporate	Consolidations and Eliminations	Consolidated Company
Three Months Ended June 30, 2018					
Oil and natural gas revenues	$207,229	$1,790	$—	$ —	$209,019
Midstream services revenues	—	19,896	—	(16,489)	3,407
Realized loss on derivatives	(2,488)	—	—	—	(2,488)
Unrealized gain on derivatives	1,429	—	—	—	1,429
Expenses(1)	126,025	9,363	18,475	(16,489)	137,374
Operating income (loss)(2)	$80,145	$12,323	$(18,475)	$ —	$73,993
Total assets	$2,058,447	$354,068	$143,332	$ —	$2,555,847
Capital expenditures(3)	$199,345	$32,900	$732	$ —	$232,977

(1) Includes depletion, depreciation and amortization expenses of $64.5 million and $2.3 million for the exploration and production and midstream segments, respectively. Also includes corporate depletion, depreciation and amortization expenses of $25,000.
(2) Includes $5.8 million in net income attributable to non-controlling interest in subsidiaries related to the midstream segment.
(3) Includes $16.1 million in capital expenditures attributable to non-controlling interest in subsidiaries related to the midstream segment.

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NOTE 11 — SEGMENT INFORMATION — Continued

	Exploration and Production	Midstream	Corporate	Consolidations and Eliminations	Consolidated Company
Three Months Ended June 30, 2017					
Oil and natural gas revenues	$113,387	$377	$—	$ —	$113,764
Midstream services revenues	—	11,367	—	(9,268)	2,099
Realized gain on derivatives	558	—	—	—	558
Unrealized gain on derivatives	13,190	—	—	—	13,190
Expenses(1)	78,078	5,960	15,852	(9,268)	90,622
Operating income (loss)(2)	$49,057	$5,784	$(15,852)	$ —	$38,989
Total assets	$1,436,678	$192,889	$147,509	$ —	$1,777,076
Capital expenditures(3)	$165,583	$27,347	$1,752	$ —	$194,682

(1) Includes depletion, depreciation and amortization expenses of $39.6 million and $1.3 million for the exploration and production and midstream segments, respectively. Also includes corporate depletion, depreciation and amortization expenses of $0.4 million.

(2) Includes $3.2 million in net income attributable to non-controlling interest in subsidiaries related to the midstream segment.

(3) Includes $13.4 million in capital expenditures attributable to non-controlling interest in subsidiaries related to the midstream segment.

	Exploration and Production	Midstream	Corporate	Consolidations and Eliminations	Consolidated Company
Six Months Ended June 30, 2018					
Oil and natural gas revenues	$387,489	$3,484	$—	$ —	$390,973
Midstream services revenues	—	35,708	—	(29,233)	6,475
Realized loss on derivatives	(6,746)	—	—	—	(6,746)
Unrealized gain on derivatives	11,845	—	—	—	11,845
Expenses(1)	232,180	16,561	35,684	(29,233)	255,192
Operating income (loss)(2)	$160,408	$22,631	$(35,684)	$ —	$147,355
Total assets	$2,058,447	$354,068	$143,332	$ —	$2,555,847
Capital expenditures(3)	$388,790	$78,617	$1,258	$ —	$468,665

(1) Includes depletion, depreciation and amortization expenses of $117.8 million and $3.9 million for the exploration and production and midstream segments, respectively. Also includes corporate depletion, depreciation and amortization expenses of $0.6 million.

(2) Includes $10.9 million in net income attributable to non-controlling interest in subsidiaries related to the midstream segment.

(3) Includes $38.5 million in capital expenditures attributable to non-controlling interest in subsidiaries related to the midstream segment.

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NOTE 11 — SEGMENT INFORMATION — Continued

	Exploration and Production	Midstream	Corporate	Consolidations and Eliminations	Consolidated Company
Six Months Ended June 30, 2017					
Oil and natural gas revenues	$227,552	$1,059	$—	$ —	$228,611
Midstream services revenues	—	20,983	—	(17,329)	3,654
Realized loss on derivatives	(1,661)	—	—	—	(1,661)
Unrealized gain on derivatives	33,821	—	—	—	33,821
Expenses(1)	146,416	10,462	31,608	(17,329)	171,157
Operating income (loss)(2)	$113,296	$11,580	$(31,608)	$ —	$93,268
Total assets	$1,436,678	$192,889	$147,509	$ —	$1,777,076
Capital expenditures(3)	$373,956	$40,227	$3,216	$ —	$417,399

(1) Includes depletion, depreciation and amortization expenses of $72.1 million and $2.5 million for the exploration and production and midstream segments, respectively. Also includes corporate depletion, depreciation and amortization expenses of $0.7 million.

(2) Includes $5.1 million in net income attributable to non-controlling interest in subsidiaries related to the midstream segment.

(3) Includes $18.6 million in capital expenditures attributable to non-controlling interest in subsidiaries related to the midstream segment.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS — UNAUDITED — CONTINUED

NOTE 12 — SUBSIDIARY GUARANTORS

The Notes are jointly and severally guaranteed by certain subsidiaries of Matador (the "Guarantor Subsidiaries") on a full and unconditional basis (except for customary release provisions). At June 30, 2018, the Guarantor Subsidiaries were 100% owned by Matador. Matador is a parent holding company and has no independent assets or operations, and there are no significant restrictions on the ability of Matador to obtain funds from the Guarantor Subsidiaries by dividend or loan. San Mateo and its subsidiaries (the "Non-Guarantor Subsidiaries") are not guarantors of the Notes. The following presents condensed consolidating financial information of the issuer (Matador), the Non-Guarantor Subsidiaries, the Guarantor Subsidiaries and all entities on a consolidated basis (in thousands). Elimination entries are necessary to combine the entities. This financial information is presented in accordance with the requirements of Rule 3-10 of Regulation S-X. The following financial information may not necessarily be indicative of results of operations, cash flows or financial position had the Guarantor Subsidiaries operated as independent entities.

Condensed Consolidating Balance Sheet
June 30, 2018

	Matador	Non-Guarantor Subsidiaries	Guarantor Subsidiaries	Eliminating Entries	Consolidated
ASSETS					
Intercompany receivable	$811,982	$ 8,235	$—	$(820,217)	$—
Third-party current assets	3,031	29,358	288,548	—	320,937
Net property and equipment	—	299,258	1,928,759	—	2,228,017
Investment in subsidiaries	1,285,896	—	162,418	(1,448,314)	—
Third-party long-term assets	6,433	—	3,394	(2,934)	6,893
Total assets	$2,107,342	$ 336,851	$2,383,119	$(2,271,465)	$2,555,847
LIABILITIES AND EQUITY					
Intercompany payable	$—	$ —	$820,217	$(820,217)	$—
Third-party current liabilities	8,646	15,482	239,726	(256)	263,598
Senior unsecured notes payable	574,164	—	—	—	574,164
Other third-party long-term liabilities	—	3,735	37,280	(2,678)	38,337
Total equity attributable to Matador Resources Company	1,524,532	162,418	1,285,896	(1,448,314)	1,524,532
Non-controlling interest in subsidiaries	—	155,216	—	—	155,216
Total liabilities and equity	$2,107,342	$ 336,851	$2,383,119	$(2,271,465)	$2,555,847

Condensed Consolidating Balance Sheet
December 31, 2017

	Matador	Non-Guarantor Subsidiaries	Guarantor Subsidiaries	Eliminating Entries	Consolidated
ASSETS					
Intercompany receivable	$585,109	$ 2,912	$—	$(588,021)	$—
Third-party current assets	2,240	9,334	245,596	—	257,170
Net property and equipment	—	223,178	1,658,278	—	1,881,456
Investment in subsidiaries	1,147,295	—	111,077	(1,258,372)	—
Third-party long-term assets	6,425	—	3,642	(3,003)	7,064
Total assets	$1,741,069	$ 235,424	$2,018,593	$(1,849,396)	$2,145,690
LIABILITIES AND EQUITY					
Intercompany payable	$—	$ —	$588,021	$(588,021)	$—
Third-party current liabilities	8,847	19,891	254,142	(274)	282,606

Senior unsecured notes payable	574,073	—	—	—	574,073
Other third-party long-term liabilities	1,593	3,466	29,135	(2,729)	31,465
Total equity attributable to Matador Resources Company	1,156,556	111,077	1,147,295	(1,258,372)	1,156,556
Non-controlling interest in subsidiaries	—	100,990	—	—	100,990
Total liabilities and equity	$1,741,069	$ 235,424	$2,018,593	$(1,849,396)	$2,145,690

Condensed Consolidating Statement of Operations
For the Three Months Ended June 30, 2018

	Matador	Non-Guarantor Subsidiaries	Guarantor Subsidiaries	Eliminating Entries	Consolidated
Total revenues	$—	$ 21,356	$ 206,219	$(16,208)	$ 211,367
Total expenses	1,178	9,466	142,938	(16,208)	137,374
Operating (loss) income	(1,178)	11,890	63,281	—	73,993
Interest expense	(8,004)	—	—	—	(8,004)
Other income (expense)	—	11	(363)	—	(352)
Earnings in subsidiaries	68,988	—	6,070	(75,058)	—
Income before income taxes	59,806	11,901	68,988	(75,058)	65,637
Net income attributable to non-controlling interest in subsidiaries	—	(5,831)	—	—	(5,831)
Net income attributable to Matador Resources Company shareholders	$59,806	$ 6,070	$ 68,988	$(75,058)	$ 59,806

Condensed Consolidating Statement of Operations
For the Three Months Ended June 30, 2017

	Matador	Non-Guarantor Subsidiaries	Guarantor Subsidiaries	Eliminating Entries	Consolidated
Total revenues	$—	$ 11,274	$ 127,198	$(8,861)	$ 129,611
Total expenses	1,586	4,814	93,083	(8,861)	90,622
Operating (loss) income	(1,586)	6,460	34,115	—	38,989
Interest expense	(9,224)	—	—	—	(9,224)
Other (expense) income	(27)	26	1,923	—	1,922
Earnings in subsidiaries	39,228	—	3,244	(42,472)	—
Income before income taxes	28,391	6,486	39,282	(42,472)	31,687
Total income tax (benefit) provision	(118)	64	54	—	—
Net income attributable to non-controlling interest in subsidiaries	—	(3,178)	—	—	(3,178)
Net income attributable to Matador Resources Company shareholders	$28,509	$ 3,244	$ 39,228	$(42,472)	$ 28,509

Condensed Consolidating Statement of Operations
For the Six Months Ended June 30, 2018

	Matador	Non-Guarantor Subsidiaries	Guarantor Subsidiaries	Eliminating Entries	Consolidated
Total revenues	$—	$ 38,550	$ 392,699	$(28,702)	$ 402,547
Total expenses	2,412	16,394	265,088	(28,702)	255,192
Operating (loss) income	(2,412)	22,156	127,611	—	147,355
Interest expense	(16,495)	—	—	—	(16,495)
Other income (expense)	6	11	(316)	—	(299)
Earnings in subsidiaries	138,601	—	11,306	(149,907)	—
Income before income taxes	119,700	22,167	138,601	(149,907)	130,561
Net income attributable to non-controlling interest in subsidiaries	—	(10,861)	—	—	(10,861)
	$119,700	$ 11,306	$ 138,601	$(149,907)	$ 119,700

Net income attributable to Matador Resources Company shareholders

Condensed Consolidating Statement of Operations
For the Six Months Ended June 30, 2017

	Matador	Non-Guarantor Subsidiaries	Guarantor Subsidiaries	Eliminating Entries	Consolidated
Total revenues	$—	$ 20,937	$ 259,846	$ (16,358)	$ 264,425
Total expenses	2,846	8,682	175,987	(16,358)	171,157
Operating (loss) income	(2,846)	12,255	83,859	—	93,268
Net gain on asset sales and inventory impairment	—	—	7	—	7
Interest expense	(17,679)	—	—	—	(17,679)
Other income	—	26	1,965	—	1,991
Earnings in subsidiaries	92,900	—	7,069	(99,969)	—
Income before income taxes	72,375	12,281	92,900	(99,969)	77,587
Total income tax (benefit) provision	(118)	118	—	—	—
Net income attributable to non-controlling interest in subsidiaries	—	(5,094)	—	—	(5,094)
Net income attributable to Matador Resources Company shareholders	$72,493	$ 7,069	$ 92,900	$ (99,969)	$ 72,493

Condensed Consolidating Statement of Cash Flows
For the Six Months Ended June 30, 2018

	Matador	Non-Guarantor Subsidiaries	Guarantor Subsidiaries	Eliminating Entries	Consolidated
Net cash (used in) provided by operating activities	$(224,441)	$ 10,225	$ 468,424	$ —	$ 254,208
Net cash used in investing activities	—	(79,119)	(454,478)	40,035	(493,562)
Net cash provided by financing activities	226,539	83,400	10,481	(40,035)	280,385
Increase in cash and restricted cash	2,098	14,506	24,427	—	41,031
Cash and restricted cash at beginning of period	286	5,663	96,533	—	102,482
Cash and restricted cash at end of period	$2,384	$ 20,169	$ 120,960	$ —	$ 143,513

Condensed Consolidating Statement of Cash Flows
For the Six Months Ended June 30, 2017

	Matador	Non-Guarantor Subsidiaries	Guarantor Subsidiaries	Eliminating Entries	Consolidated
Net cash (used in) provided by operating activities	$(98,583)	$ 1,566	$ 218,259	$ —	$ 121,242
Net cash provided by (used in) investing activities	33	(38,362)	(197,486)	(133,880)	(369,695)
Net cash provided by (used in) financing activities	—	47,707	(769)	133,880	180,818
(Decrease) increase in cash and restricted cash	(98,550)	10,911	20,004	—	(67,635)
Cash and restricted cash at beginning of period	99,795	2,900	111,447	—	214,142
Cash and restricted cash at end of period	$1,245	$ 13,811	$ 131,451	$ —	$ 146,507

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our interim unaudited condensed consolidated financial statements and related notes thereto contained herein and the consolidated financial statements and related notes thereto contained in our Annual Report on Form 10-K for the year ended December 31, 2017 (the "Annual Report") filed with the Securities and Exchange Commission ("SEC"), along with Management's Discussion and Analysis of Financial Condition and Results of Operations contained in the Annual Report. The Annual Report is accessible on the SEC's website at www.sec.gov and on our website at www.matadorresources.com. Our discussion and analysis includes forward-looking information that involves risks and uncertainties and should be read in conjunction with the "Risk Factors" section of the Annual Report and the section entitled "Cautionary Note Regarding Forward-Looking Statements" below for information about the risks and uncertainties that could cause our actual results to be materially different than our forward-looking statements.

In this Quarterly Report on Form 10-Q (the "Quarterly Report"), references to "we," "our" or the "Company" refer to Matador Resources Company and its subsidiaries as a whole (unless the context indicates otherwise) and references to "Matador" refer solely to Matador Resources Company. For certain oil and natural gas terms used in this Quarterly Report, please see the "Glossary of Oil and Natural Gas Terms" included with the Annual Report.

Cautionary Note Regarding Forward-Looking Statements

Certain statements in this Quarterly Report constitute "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, as amended, or the Exchange Act. Additionally, forward-looking statements may be made orally or in press releases, conferences, reports, on our website or otherwise, in the future by us or on our behalf. Such statements are generally identifiable by the terminology used such as "anticipate," "believe," "continue," "could," "estimate," "expect," "forecasted," "hypothetical," "intend," "may," "might," "plan," "potential," "predict," "project," "should," "would" or other si although not all forward-looking statements contain such identifying words.

By their very nature, forward-looking statements require us to make assumptions that may not materialize or that may not be accurate. Forward-looking statements are subject to known and unknown risks and uncertainties and other factors that may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include, among others: general economic conditions, changes in oil, natural gas and natural gas liquids prices and the demand for oil, natural gas and natural gas liquids, the success of our drilling program, the timing of planned capital expenditures, the sufficiency of our cash flow from operations together with available borrowing capacity under our credit agreement, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as our ability to access them, the proximity to our properties and capacity of transportation facilities, availability of acquisitions, our ability to integrate acquisitions with our business, weather and environmental conditions, uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, and the other factors discussed below and elsewhere in this Quarterly Report and in other documents that we file with or furnish to the SEC, all of which are difficult to predict. Forward-looking statements may include statements about:

- our business strategy;
- our reserves;
- our technology;
- our cash flows and liquidity;
- our financial strategy, budget, projections and operating results;
- our oil and natural gas realized prices;
- the timing and amount of future production of oil and natural gas;
- the availability of drilling and production equipment;
- the availability of oil field labor;
- the amount, nature and timing of capital expenditures, including future exploration and development costs;
- the availability and terms of capital;

- our drilling of wells;
- our ability to negotiate and consummate acquisition and divestiture opportunities;
- government regulation and taxation of the oil and natural gas industry;
- our marketing of oil and natural gas;
- our exploitation projects or property acquisitions;
- the integration of acquisitions with our business;

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- our ability and the ability of our midstream joint venture to construct and operate midstream facilities, including the operation of our Black River cryogenic natural gas processing plant and the drilling of additional salt water disposal wells;
- the ability of our midstream joint venture to attract third-party volumes;
- our costs of exploiting and developing our properties and conducting other operations;
- general economic conditions;
- competition in the oil and natural gas industry, including in both the exploration and production and midstream segments;
- the effectiveness of our risk management and hedging activities;
- environmental liabilities;
- counterparty credit risk;
- developments in oil-producing and natural gas-producing countries;
- our future operating results;
- estimated future reserves and the present value thereof; and
- our plans, objectives, expectations and intentions contained in this Quarterly Report or in our other filings with the SEC that are not historical.

Although we believe that the expectations conveyed by the forward-looking statements in this Quarterly Report are reasonable based on information available to us on the date hereof, no assurances can be given as to future results, levels of activity, achievements or financial condition.

You should not place undue reliance on any forward-looking statement and should recognize that the statements are predictions of future results, which may not occur as anticipated. Actual results could differ materially from those anticipated in the forward-looking statements and from historical results, due to the risks and uncertainties described above, as well as others not now anticipated. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are interdependent upon other factors. The foregoing statements are not exclusive and further information concerning us, including factors that potentially could materially affect our financial results, may emerge from time to time. We undertake no obligation to update forward-looking statements to reflect actual results or changes in factors or assumptions affecting such forward-looking statements, except as required by law, including the securities laws of the United States and the rules and regulations of the SEC.

Overview

We are an independent energy company engaged in the exploration, development, production and acquisition of oil and natural gas resources in the United States, with an emphasis on oil and natural gas shale and other unconventional plays. Our current operations are focused primarily on the oil and liquids-rich portion of the Wolfcamp and Bone Spring plays in the Delaware Basin in Southeast New Mexico and West Texas. We also operate in the Eagle Ford shale play in South Texas and the Haynesville shale and Cotton Valley plays in Northwest Louisiana and East Texas. Additionally, we conduct midstream operations, primarily through our midstream joint venture, San Mateo Midstream, LLC ("San Mateo"), in support of our exploration, development and production operations and provide natural gas processing, oil transportation services, oil, natural gas and salt water gathering services and salt water disposal services to third parties.

Second Quarter and Year-to-Date Highlights

For the three months ended June 30, 2018, our total oil equivalent production was 4.8 million BOE, and our average daily oil equivalent production was 52,937 BOE per day, of which 29,740 Bbl per day, or 56%, was oil and 139.2 MMcf per day, or 44%, was natural gas. Our oil production of 2.7 million Bbl for the three months ended June 30, 2018 increased 53% year-over-year from 1.8 million Bbl for the three months ended June 30, 2017. Our natural gas production of 12.7 Bcf for the three months ended June 30, 2018 increased 33% year-over-year from 9.6 Bcf for the three months ended June 30, 2017. For the six months ended June 30, 2018, our total oil equivalent production was 8.9 million BOE, and our average daily oil equivalent production was 49,126 BOE per day, of which 28,111 Bbl per day, or 57%, was oil and 126.1 MMcf per day, or 43%, was natural gas. Our oil production of 5.1 million Bbl for the six months ended June 30, 2018 increased 49% year-over-year from 3.4 million Bbl for the six months ended June 30, 2017. Our natural gas production of 22.8 Bcf for the six months ended June 30, 2018 increased 31% year-over-year from 17.5 Bcf for the six months ended June 30, 2017.

For the second quarter of 2018, we reported net income attributable to Matador Resources Company shareholders of approximately $59.8 million, or $0.53 per diluted common share, on a GAAP basis, as compared to net income attributable to Matador Resources Company shareholders of $28.5 million, or $0.28 per diluted common share, for the second quarter of 2017. For the second quarter of 2018, our Adjusted EBITDA attributable to Matador Resources Company shareholders (“Adjusted EBITDA”), a non-GAAP financial measure, was $137.3 million, as compared to Adjusted EBITDA of $72.7 million during the second quarter of 2017. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income and

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net cash provided by operating activities, see "— Liquidity and Capital Resources — Non-GAAP Financial Measures." For more information regarding our financial results for the second quarter of 2018, see "— Results of Operations" below.

For the six months ended June 30, 2018, we reported net income attributable to Matador Resources Company shareholders of approximately $119.7 million, or $1.08 per diluted common share, on a GAAP basis, as compared to net income attributable to Matador Resources Company shareholders of $72.5 million, or $0.72 per diluted common share, for the six months ended June 30, 2017. For the six months ended June 30, 2018, our Adjusted EBITDA, a non-GAAP financial measure, was $254.6 million, as compared to Adjusted EBITDA of $142.6 million during the six months ended June 30, 2017. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see "— Liquidity and Capital Resources — Non-GAAP Financial Measures." For more information regarding our financial results for the six months ended June 30, 2018, see "— Results of Operations" below.

During the second quarter of 2018, we continued our focus on the exploration, delineation and development of our Delaware Basin acreage in Loving County, Texas and Lea and Eddy Counties, New Mexico. We began 2018 operating six drilling rigs in the Delaware Basin and continued to do so throughout the first half of 2018. We expect to operate those six rigs in the Delaware Basin throughout 2018, including three rigs in the Rustler Breaks asset area, one rig in the Wolf/Jackson Trust asset areas, one rig in the Ranger/Arrowhead and Twin Lakes asset areas and one rig in the Antelope Ridge asset area. Depending on commodity prices and basis differentials, capital and operating costs, opportunities in asset areas like Arrowhead and Antelope Ridge, liquidity and other factors, we may consider adding a seventh rig during the fourth quarter of 2018, although we had not made the decision to do so at August 1, 2018. Should we elect to add a seventh drilling rig during the fourth quarter of 2018, we anticipate this additional rig will have no impact on our estimated 2018 oil and natural gas production and only a minor impact on our anticipated capital expenditures for the remainder of 2018.

During the second quarter of 2018, we did not conduct any operated drilling and completion activities on our leasehold properties in the Eagle Ford shale play in South Texas or in the Haynesville shale and Cotton Valley plays in Northwest Louisiana and East Texas. We did participate in the drilling and completion of three gross (0.2 net) non-operated Haynesville shale wells that were turned to sales in the second quarter of 2018.

We completed and turned to sales a total of 33 gross (19.3 net) wells in the Delaware Basin during the second quarter of 2018, including 24 gross (18.5 net) operated horizontal wells and nine gross (0.8 net) non-operated horizontal wells. During the second quarter of 2018, we began producing oil and natural gas from a total of three gross (0.6 net) wells in the Antelope Ridge asset area, including one gross (0.5 net) operated and two gross (0.1 net) non-operated wells. The one gross operated well was a First Bone Spring completion. In the Rustler Breaks asset area, we began producing oil and natural gas from a total of 23 gross (13.6 net) wells during the second quarter of 2018, including 16 gross (12.9 net) operated and seven gross (0.7 net) non-operated wells. Of the 16 gross operated wells in the Rustler Breaks asset area, nine were Wolfcamp A-XY completions, two were Wolfcamp A-Lower completions, four were Wolfcamp B-Blair completions and one was a Second Bone Spring completion. In addition, we began producing oil and natural gas from three gross (2.7 net) operated wells in the Wolf and Jackson Trust asset areas during the second quarter of 2018, all three of which were Wolfcamp A-XY completions. Finally, in the Arrowhead asset area, we began producing oil and natural gas from four gross (2.4 net) operated wells, including three Second Bone Spring completions and one Third Bone Spring completion, during the second quarter of 2018.

As a result of our ongoing drilling and completion operations in these asset areas, our Delaware Basin production has continued to increase over the past twelve months. Our total Delaware Basin production for the second quarter of 2018 was 46,489 BOE per day, consisting of 27,381 Bbl of oil per day and 114.6 MMcf of natural gas per day, a 68% increase from production of 27,622 BOE per day, consisting of 16,645 Bbl of oil per day and 65.9 MMcf of natural gas per day, in the second quarter of 2017. The Delaware Basin contributed approximately 92% of our daily oil production and approximately 82% of our daily natural gas production in the second quarter of 2018, as compared to approximately 86% of our daily oil production and approximately 63% of our daily natural gas production in the second quarter of 2017.

On May 17, 2018, we completed a public offering of 7,000,000 shares of our common stock. After deducting offering costs totaling approximately $0.1 million, we received net proceeds of approximately $226.5 million. The proceeds from this offering were and are being used to acquire additional leasehold and mineral acres in the Delaware Basin, to fund certain midstream initiatives in the Delaware Basin and for general corporate purposes, including to fund a portion of our future capital expenditures. Pending such uses, we used a portion of the proceeds from the offering to repay the $45.0 million of outstanding borrowings under our third amended and restated revolving credit facility, as amended (the “Credit Agreement”), and invested the remaining funds in short-term marketable securities.

From January 1 through August 1, 2018, we acquired or had under contract approximately 16,000 net leasehold and mineral acres in and around our existing acreage positions in the Delaware Basin, including approximately 3,400 net mineral acres. From January 1 through August 1, 2018, we had incurred net capital expenditures of approximately $155 million to acquire approximately 9,500 net acres of these leasehold and mineral interests. We expect to incur net capital expenditures of approximately $32 million to acquire the additional approximately 6,500 net acres in leasehold and mineral interests that were under contract as of August 1, 2018 during the third and fourth quarters of 2018; the purchase price for such additional acquisitions is expected to be funded with a portion of the proceeds of our May 2018 equity offering. We intend to continue acquiring acreage and mineral interests, principally in the Delaware Basin, during the remainder of 2018.

2018 Capital Expenditure Budget

As of August 1, 2018, we adjusted our anticipated capital expenditures for drilling and completions (including equipping wells for production) from $530 to $570 million to $620 to $650 million and our anticipated midstream capital expenditures remained $70 to $90 million, which represents our 51% share of San Mateo's 2018 estimated capital expenditures. We have allocated substantially all of our estimated 2018 capital expenditures to the further delineation and development of our growing leasehold position and midstream assets in the Delaware Basin, with the exception of amounts allocated to limited operations in the Eagle Ford and Haynesville shales. For the remainder of 2018, our Delaware Basin drilling program will continue to focus on the development of the Wolf and Rustler Breaks asset areas and the further delineation and development of the Jackson Trust, Ranger/Arrowhead, Antelope Ridge and Twin Lakes asset areas, although we may also continue to delineate previously untested zones in the Wolf and Rustler Breaks asset areas.

Natural Gas Sales Agreement with Kinder Morgan

In May 2018, we entered into a firm sales agreement with an affiliate of Kinder Morgan, Inc. beginning on the in-service date of the Gulf Coast Express Pipeline Project (the "GCX Project"). The agreement secures firm natural gas sales for an average of approximately 110,000 to 115,000 million British Thermal Units ("MMBtu") per day at a price based upon Houston Ship Channel pricing. The GCX Project is expected to be operational in October 2019 and is expected to transport natural gas from the Permian Basin to Agua Dulce, Texas near the Texas Gulf Coast.

Salt Water Gathering and Disposal Agreement

In June 2018, a subsidiary of San Mateo entered into a long-term agreement with a third party in Eddy County, New Mexico to gather and dispose of the third party's produced salt water. The agreement includes the dedication of certain of the third party's wells, which are or will be located near San Mateo's existing salt water gathering system in Eddy County, New Mexico.

Estimated Proved Reserves

The following table sets forth our estimated total proved oil and natural gas reserves at June 30, 2018, December 31, 2017 and June 30, 2017. Our production and proved reserves are reported in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Where we produce liquids-rich natural gas, such as in the Delaware Basin and the Eagle Ford shale, the economic value of the NGLs associated with the natural gas is included in the estimated wellhead natural gas price on those properties where the NGLs are extracted and sold. These reserves estimates were based on evaluations prepared by our engineering staff and have been audited for their reasonableness and conformance with SEC guidelines by Netherland, Sewell & Associates, Inc., independent reservoir engineers. These reserves estimates were prepared in accordance with the SEC's rules for oil and natural gas reserves reporting. The estimated reserves shown are for proved reserves only and do not include any unproved reserves classified as probable or possible reserves that might exist for our properties, nor do they include any consideration that would be attributable to interests in unproved and unevaluated acreage beyond those tracts for which proved reserves have been estimated. Proved oil and natural gas reserves are quantities of oil and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Our total proved reserves are estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

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	June 30, 2018	December 31, 2017	June 30, 2017
Estimated Proved Reserves Data:[(1)(2)]			
Estimated proved reserves:			
Oil (MBbl)[(3)]	95,448	86,743	74,954
Natural Gas (Bcf)[(4)]	448.2	396.2	356.5
Total (MBOE)[(5)]	170,155	152,771	134,373
Estimated proved developed reserves:			
Oil (MBbl)[(3)]	45,030	36,966	28,454
Natural Gas (Bcf)[(4)]	224.3	190.1	159.7
Total (MBOE)[(5)]	82,415	68,651	55,075
Percent developed	48.4 %	44.9 %	41.0 %
Estimated proved undeveloped reserves:			
Oil (MBbl)[(3)]	50,418	49,777	46,500
Natural Gas (Bcf)[(4)]	223.9	206.1	196.8
Total (MBOE)[(5)]	87,740	84,120	79,298
Standardized Measure[(6)] (in millions)	$1,613.3	$1,258.6	$1,001.9
PV-10[(7)] (in millions)	$1,765.9	$1,333.4	$1,086.9

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(1) Numbers in table may not total due to rounding.

(2) Our estimated proved reserves, Standardized Measure and PV-10 were determined using index prices for oil and natural gas, without giving effect to derivative transactions, and were held constant throughout the life of the properties. The unweighted arithmetic averages of the first-day-of-the-month prices for the period from July 2017 through June 2018 were $54.15 per Bbl for oil and $2.92 per MMBtu for natural gas, for the period from January 2017 through December 2017 were $47.79 per Bbl for oil and $2.98 per MMBtu for natural gas and for the period from July 2016 through June 2017 were $45.42 per Bbl for oil and $3.01 per MMBtu for natural gas. These prices were adjusted by property for quality, energy content, regional price differentials, transportation fees, marketing deductions and other factors affecting the price received at the wellhead. We report our proved reserves in two streams, oil and natural gas, and the economic value of the NGLs associated with the natural gas is included in the estimated wellhead natural gas price on those properties where the NGLs are extracted and sold.

(3) One thousand barrels of oil.

(4) One billion cubic feet of natural gas.

(5) One thousand barrels of oil equivalent, estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(6) Standardized Measure represents the present value of estimated future net cash flows from proved reserves, less estimated future development, production, plugging and abandonment costs and income tax expenses, discounted at 10% per annum to reflect the timing of future cash flows. Standardized Measure is not an estimate of the fair market value of our properties.

(7) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. PV-10 is not an estimate of the fair market value of our properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies and of the potential return on investment related to the companies' properties without regard to the specific tax characteristics of such entities. Our PV-10 at June 30, 2018, December 31, 2017 and June 30, 2017 may be reconciled to the Standardized Measure of discounted future net cash flows at such dates by reducing our PV-10 by the discounted future income taxes associated with such reserves. The discounted future income taxes at June 30, 2018, December 31, 2017 and June 30, 2017 were $152.6 million, $74.8 million and $85.0 million, respectively.

At June 30, 2018, our estimated total proved oil and natural gas reserves were 170.2 million BOE, including 95.4 million Bbl of oil and 448.2 Bcf of natural gas, with a Standardized Measure of $1.6 billion and a PV-10, a non-GAAP financial measure, of $1.8 billion. At December 31, 2017, our estimated total proved oil and natural gas reserves were 152.8 million BOE, including 86.7 million Bbl of oil and 396.2 Bcf of natural gas, and at June 30, 2017, our estimated total proved oil and natural gas reserves were 134.4 million BOE, including 75.0 million Bbl of oil and 356.5 Bcf of natural gas. Our proved oil reserves of 95.4 million Bbl at June 30, 2018 increased 10%, as compared to 86.7 million Bbl at December 31, 2017, and increased 27%, as compared to 75.0 million Bbl at June 30, 2017. At June 30, 2018, approximately 48% of our total proved reserves were proved developed reserves, 56% of our total proved reserves were oil and 44% of our total proved reserves were natural gas.

As a result of our drilling, completion and delineation activities in Southeast New Mexico and West Texas since 2014, our Delaware Basin oil and natural gas reserves have become a more significant component of our total oil and natural gas reserves.

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Our estimated Delaware Basin proved oil and natural gas reserves increased 37% from 108.1 million BOE at June 30, 2017, or 80% of our total proved oil and natural gas reserves, including 64.9 million Bbl of oil and 259.2 Bcf of natural gas, to 148.5 million BOE, or 87% of our total proved oil and natural gas reserves, including 87.1 million Bbl of oil and 368.7 Bcf of natural gas, at June 30, 2018.

There have been no changes to the technology we used to establish reserves or to our internal control over the reserves estimation process from those set forth in the Annual Report.

Critical Accounting Policies

Other than as discussed in Note 2 to the interim unaudited condensed consolidated financial statements in this Quarterly Report related to the adoption of Accounting Standards Update 2014-09, Revenue from Contracts with Customers (Topic 606), there have been no changes to our critical accounting policies and estimates from those set forth in the Annual Report.

Recent Accounting Pronouncements

See Note 2 to the interim unaudited condensed consolidated financial statements in this Quarterly Report for a summary of recent accounting pronouncements that we believe may have an impact on our financial statements upon adoption.

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Results of Operations

Revenues

The following table summarizes our unaudited revenues and production data for the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Operating Data:				
Revenues (in thousands):[1]				
Oil	$166,271	$81,322	$314,430	$164,958
Natural gas	42,748	32,442	76,543	63,653
Total oil and natural gas revenues	209,019	113,764	390,973	228,611
Third-party midstream services revenues	3,407	2,099	6,475	3,654
Realized (loss) gain on derivatives	(2,488)	558	(6,746)	(1,661)
Unrealized gain on derivatives	1,429	13,190	11,845	33,821
Total revenues	$211,367	$129,611	$402,547	$264,425
Net Production Volumes:[1]				
Oil (MBbl)[2]	2,706	1,767	5,088	3,417
Natural gas (Bcf)[3]	12.7	9.6	22.8	17.5
Total oil equivalent (MBOE)[4]	4,817	3,360	8,892	6,330
Average daily production (BOE/d)[5]	52,937	36,922	49,126	34,972
Average Sales Prices:				
Oil, without realized derivatives (per Bbl)	$61.44	$46.01	$61.80	$48.28
Oil, with realized derivatives (per Bbl)	$60.52	$46.34	$60.46	$47.97
Natural gas, without realized derivatives (per Mcf)	$3.38	$3.40	$3.35	$3.64
Natural gas, with realized derivatives (per Mcf)	$3.38	$3.39	$3.36	$3.61

(1) We report our production volumes in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Revenues associated with NGLs are included with our natural gas revenues.

(2) One thousand barrels of oil.

(3) One billion cubic feet of natural gas.

(4) One thousand barrels of oil equivalent, estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(5) Barrels of oil equivalent per day, estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

Three Months Ended June 30, 2018 as Compared to Three Months Ended June 30, 2017

Oil and natural gas revenues. Our oil and natural gas revenues increased $95.3 million to $209.0 million, or 84%, for the three months ended June 30, 2018, as compared to $113.8 million for the three months ended June 30, 2017. Our oil revenues increased $84.9 million, or 104%, to $166.3 million for the three months ended June 30, 2018, as compared to $81.3 million for the three months ended June 30, 2017. The increase in oil revenues resulted from (i) a higher weighted average oil price realized for the three months ended June 30, 2018 of $61.44 per Bbl, as compared to $46.01 per Bbl realized for the three months ended June 30, 2017, and (ii) the 53% increase in our oil production to 2.7 million Bbl of oil for the three months ended June 30, 2018, or 29,740 Bbl of oil per day, as compared to 1.8 million Bbl of oil, or 19,423 Bbl of oil per day, for the three months ended June 30, 2017. The increase in oil production was primarily attributable to our ongoing delineation and development drilling activities in the Delaware Basin. Our natural gas revenues increased by $10.3 million, or 32%, to $42.7 million for the three months ended June 30, 2018, as compared to $32.4 million for the three months ended June 30, 2017. The increase in natural gas revenues resulted from the 33% increase in our natural gas production to 12.7 Bcf for the three months ended June 30, 2018, as compared to 9.6 Bcf for the three months ended June 30, 2017. The increase in natural gas production was primarily attributable to our ongoing delineation and development drilling activities in the Delaware Basin.

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Third-party midstream services revenues. Our third-party midstream services revenues increased $1.3 million to $3.4 million, or 62%, for the three months ended June 30, 2018, as compared to $2.1 million for the three months ended June 30, 2017. Third-party midstream services revenues are those revenues from midstream operations related to third parties, including working interest owners in our operated wells. This increase was primarily attributable to an increase in our third-party salt water gathering and disposal revenues to approximately $1.9 million for the three months ended June 30, 2018, as compared to approximately $0.4 million for the three months ended June 30, 2017.
Realized (loss) gain on derivatives. Our realized net loss on derivatives was $2.5 million for the three months ended June 30, 2018, as compared to a realized net gain of $0.6 million for the three months ended June 30, 2017. We realized a net loss of $8.7 million related to our oil costless collar contracts for the three months ended June 30, 2018, resulting from oil prices that were above the short call/ceiling prices of certain of our oil costless collar contracts. We realized a net gain of $6.2 million related to our oil basis swap contracts for the three months ended June 30, 2018, resulting from oil basis prices lower than the swap prices of certain of our oil basis swap contracts. We realized a net gain of $0.6 million from our oil derivative contracts for the three months ended June 30, 2017 resulting from oil prices that were below the floor prices of certain of our oil costless collar contracts. We realized an average loss on our oil derivatives contracts of approximately $0.92 per Bbl produced during the three months ended June 30, 2018, as compared to an average gain of $0.33 per Bbl produced during the three months ended June 30, 2017. Our total oil volumes hedged for the three months ended June 30, 2018 represented 51% of our total oil production, as compared to 70% of our total oil production for the three months ended June 30, 2017. Our total natural gas volumes hedged for the three months ended June 30, 2018 represented 33% of our total natural gas production, as compared to 66% of our total natural gas production for the three months ended June 30, 2017.
Unrealized gain on derivatives. Our unrealized net gain on derivatives was $1.4 million for the three months ended June 30, 2018, as compared to an unrealized net gain of $13.2 million for the three months ended June 30, 2017. During the three months ended June 30, 2018, the net fair value of our open oil and natural gas derivative contracts increased to a net liability of $3.4 million from a net liability of $4.8 million at March 31, 2018, resulting in an unrealized gain on derivatives of $1.4 million for the three months ended June 30, 2018. This decrease in net liability is primarily attributable to the widening in the oil basis differential futures prices, offset by the increase in oil and natural gas futures prices during the three months ended June 30, 2018. During the three months ended June 30, 2017, the net fair value of our open oil and natural gas derivative contracts increased to a net asset of approximately $8.9 million from a net liability of $4.3 million at March 31, 2017, resulting in an unrealized gain on derivatives of $13.2 million for the three months ended June 30, 2017.
Six Months Ended June 30, 2018 as Compared to Six Months Ended June 30, 2017
Oil and natural gas revenues. Our oil and natural gas revenues increased $162.4 million to $391.0 million, or 71%, for the six months ended June 30, 2018, as compared to $228.6 million for the six months ended June 30, 2017. Our oil revenues increased $149.5 million, or 91%, to $314.4 million for the six months ended June 30, 2018, as compared to $165.0 million for the six months ended June 30, 2017. The increase in oil revenues resulted from (i) a higher weighted average oil price realized for the six months ended June 30, 2018 of $61.80 per Bbl, as compared to $48.28 per Bbl realized for the six months ended June 30, 2017, and (ii) the 49% increase in our oil production to 5.1 million Bbl of oil for the six months ended June 30, 2018, or 28,111 Bbl of oil per day, as compared to 3.4 million Bbl of oil, or 18,876 Bbl of oil per day, for the six months ended June 30, 2017. The increase in oil production was primarily attributable to our ongoing delineation and development drilling activities in the Delaware Basin. Our natural gas revenues increased by $12.9 million, or 20%, to $76.5 million for the six months ended June 30, 2018, as compared to $63.7 million for the six months ended June 30, 2017. The increase in natural gas revenues resulted from the 31% increase in our natural gas production to 22.8 Bcf for the six months ended June 30, 2018, as compared to 17.5 Bcf for the six months ended June 30, 2017, which was partially offset by a lower weighted average natural gas price realized for the six months ended June 30, 2018 of $3.35 per Mcf, as compared to $3.64 per Mcf realized for the six months ended June 30, 2017. The increase in natural gas production was primarily attributable to our ongoing delineation and development drilling activities in the Delaware Basin.
Third-party midstream services revenues. Our third-party midstream services revenues increased $2.8 million to $6.5 million, or 77%, for the six months ended June 30, 2018, as compared to $3.7 million for the six months ended June

30, 2017. This increase was primarily attributable to (i) an increase in natural gas gathering and processing revenues to approximately $3.4 million for the six months ended June 30, 2018, as compared to $2.8 million for the six months ended June 30, 2017, due to increased natural gas production in our Rustler Breaks and Wolf asset areas and (ii) an increase in our third-party salt water gathering and disposal revenues to approximately $3.0 million for the six months ended June 30, 2018, as compared to approximately $0.7 million for the six months ended June 30, 2017.
Realized loss on derivatives. Our realized net loss on derivatives was $6.7 million for the six months ended June 30, 2018, as compared to a realized net loss of $1.7 million for the six months ended June 30, 2017. We realized a net loss of $11.4 million related to our oil costless collar contracts for the six months ended June 30, 2018, resulting from oil prices that were above the short call/ceiling prices of certain of our oil costless collar contracts. We realized a net gain of $4.6 million related to our oil basis swap contracts for the six months ended June 30, 2018, resulting from oil basis prices lower than the swap prices of certain of our oil basis swap contracts. We realized a net loss of $1.1 million and $0.6 million from our oil and natural gas derivative contracts,

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respectively, for the six months ended June 30, 2017, resulting from oil and natural gas prices that were above the ceiling prices of certain of our oil and natural gas costless collar contracts. We realized an average loss on our oil derivatives of approximately $1.34 per Bbl produced during the six months ended June 30, 2018, as compared to an average loss of $0.31 per Bbl produced during the six months ended June 30, 2017. Our total oil volumes hedged for the six months ended June 30, 2018 represented 53% of our total oil production, as compared to 64% of our total oil production for the six months ended June 30, 2017. Our total natural gas volumes hedged for the six months ended June 30, 2018 represented 37% of our total natural gas production, as compared to 66% of our total natural gas production for the six months ended June 30, 2017.

Unrealized gain on derivatives. Our unrealized net gain on derivatives was $11.8 million for the six months ended June 30, 2018, as compared to an unrealized net gain of $33.8 million for the six months ended June 30, 2017. During the period from December 31, 2017 through June 30, 2018, the aggregate net fair value of our open oil and natural gas derivative contracts increased from a net liability of approximately $15.2 million to a net liability of approximately $3.4 million, resulting in an unrealized gain on derivatives of approximately $11.8 million for the six months ended June 30, 2018. This decrease in net liability is primarily attributable to the widening in the oil basis differential futures prices, offset by the increase in oil and natural gas futures prices during the six months ended June 30, 2018. During the period from December 31, 2016 through June 30, 2017, the aggregate net fair value of our open oil and natural gas derivative contracts increased from a net liability of approximately $25.0 million to a net asset of approximately $8.9 million, resulting in an unrealized gain on derivatives of approximately $33.8 million for the six months ended June 30, 2017.

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Expenses

The following table summarizes our unaudited operating expenses and other income (expense) for the periods indicated:

(In thousands, except expenses per BOE)	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
Expenses:				
Production taxes, transportation and processing	$20,110	$12,875	$37,901	$24,682
Lease operating	25,006	16,040	47,154	31,797
Plant and other midstream services operating	5,676	2,942	9,896	5,283
Depletion, depreciation and amortization	66,838	41,274	122,207	75,266
Accretion of asset retirement obligations	375	314	739	614
General and administrative	19,369	17,177	37,295	33,515
Total expenses	137,374	90,622	255,192	171,157
Operating income	73,993	38,989	147,355	93,268
Other income (expense):				
Net gain on asset sales and inventory impairment	—	—	—	7
Interest expense	(8,004)	(9,224)	(16,495)	(17,679)
Other (expense) income	(352)	1,922	(299)	1,991
Total other expense	(8,356)	(7,302)	(16,794)	(15,681)
Net income	65,637	31,687	130,561	77,587
Net income attributable to non-controlling interest in subsidiaries	(5,831)	(3,178)	(10,861)	(5,094)
Net income attributable to Matador Resources Company shareholders	$59,806	$28,509	$119,700	$72,493
Expenses per BOE:				
Production taxes, transportation and processing	$4.17	$3.83	$4.26	$3.90
Lease operating	$5.19	$4.77	$5.30	$5.02
Plant and other midstream services operating	$1.18	$0.88	$1.11	$0.83
Depletion, depreciation and amortization	$13.87	$12.28	$13.74	$11.89
General and administrative	$4.02	$5.11	$4.19	$5.29

Three Months Ended June 30, 2018 as Compared to Three Months Ended June 30, 2017

Production taxes, transportation and processing. Our production taxes, transportation and processing expenses increased $7.2 million to $20.1 million, or 56%, for the three months ended June 30, 2018, as compared to $12.9 million for the three months ended June 30, 2017. On a unit-of-production basis, our production taxes, transportation and processing expenses increased 9% to $4.17 per BOE for the three months ended June 30, 2018, as compared to $3.83 per BOE for the three months ended June 30, 2017. The increase in production taxes, transportation and processing expenses was primarily attributable to the $8.2 million increase in our production taxes to $15.1 million for the three months ended June 30, 2018, as compared to $6.9 million for the three months ended June 30, 2017, principally due to the $95.3 million increase in oil and natural gas revenues for the three months ended June 30, 2018, as compared to the three months ended June 30, 2017. In addition, the production tax rates in New Mexico are higher than production tax rates in Texas. As more of our oil and natural gas production becomes attributable to New Mexico, we expect our production tax expenses to increase proportionately.

Lease operating. Our lease operating expenses increased $9.0 million to $25.0 million, or 56%, for the three months ended June 30, 2018, as compared to $16.0 million for the three months ended June 30, 2017. Our lease operating expenses on a unit-of-production basis increased 9% to $5.19 per BOE for the three months ended June 30, 2018, as compared to $4.77 per BOE for the three months ended June 30, 2017. The increase in lease operating expenses for the three months ended June 30, 2018, as compared to the three months ended June 30, 2017, was primarily attributable to an increase in costs of services and equipment, including salt water disposal costs in asset areas other than Wolf and Rustler Breaks (which are serviced by San Mateo), at June 30, 2018, as compared to June 30, 2017.

Plant and other midstream services operating. Our plant and other midstream services operating expenses increased $2.7 million to $5.7 million, or an increase of 93%, for the three months ended June 30, 2018, as compared to $2.9 million for the three months ended June 30, 2017. This increase was primarily attributable to (i) increased expenses associated with our expanded commercial salt water disposal operations to $3.0 million for the three months ended June 30, 2018, as compared to $1.5 million for the three months ended June 30, 2017 and (ii) increased expenses associated with San Mateo's Black River cryogenic natural gas processing plant in the Rustler Breaks asset area (the "Black River Processing Plant") to $1.9 million for the three months ended June 30, 2018, as compared to $0.8 million for the three months ended June 30, 2017.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses increased $25.6 million to $66.8 million, or 62%, for the three months ended June 30, 2018, as compared to $41.3 million for the three months ended June 30, 2017. On a unit-of-production basis, our depletion, depreciation and amortization expenses increased 13% to $13.87 per BOE for the three months ended June 30, 2018, as compared to $12.28 per BOE for the three months ended June 30, 2017. The increase in our total depletion, depreciation and amortization expenses was primarily attributable to (i) increased well costs, largely as a result of increased well stimulation costs in response to increased oil prices over the past year and (ii) the 43% increase in our total oil equivalent production to 4.8 million BOE for the three months ended June 30, 2018, as compared to 3.4 million BOE for the three months ended June 30, 2017. The impact of the increase in well costs and oil and natural gas production was partially offset by higher total proved oil and natural gas reserves at June 30, 2018, as compared to June 30, 2017, primarily attributable to our ongoing delineation and development drilling activities in the Delaware Basin. In addition, depreciation expenses attributable to our midstream segment were approximately $2.3 million for the three months ended June 30, 2018, as compared to $1.3 million for the three months ended June 30, 2017.

General and administrative. Our general and administrative expenses increased $2.2 million to $19.4 million, or 13%, for the three months ended June 30, 2018, as compared to $17.2 million for the three months ended June 30, 2017. The increase in our general and administrative expenses was primarily attributable to increased payroll and related expenses of approximately $3.5 million associated with additional employees joining the Company to support our increased land, geoscience, drilling, completion, production, midstream, accounting and administration functions as a result of the continued growth of the Company. These increases were partially offset by the $1.5 million increase in capitalized general and administrative expenses for the three months ended June 30, 2018, as compared to the three months ended June 30, 2017. As a result of the 43% increase in oil and natural gas production for the three months ended June 30, 2018, as compared to the three months ended June 30, 2017, our general and administrative expenses decreased 21% on a unit-of-production basis to $4.02 per BOE for the three months ended June 30, 2018, as compared to $5.11 per BOE for the three months ended June 30, 2017.

Interest expense. For the three months ended June 30, 2018, we incurred total interest expense of approximately $10.6 million. We capitalized approximately $2.6 million of our interest expense on certain qualifying projects for the three months ended June 30, 2018 and expensed the remaining $8.0 million to operations. For the three months ended June 30, 2017, we incurred total interest expense of approximately $11.1 million. We capitalized approximately $1.9 million of our interest expense on certain qualifying projects for the three months ended June 30, 2017 and expensed the remaining $9.2 million to operations.

Total income tax benefit. Our deferred tax assets exceeded our deferred tax liabilities at June 30, 2018 due to the deferred tax amounts generated by full-cost ceiling impairment charges recorded in prior periods. As a result, we established a valuation allowance against the deferred tax assets beginning in the third quarter of 2015. We retained a full valuation allowance at June 30, 2018 due to uncertainties regarding the future realization of our deferred tax assets.

Six Months Ended June 30, 2018 as Compared to Six Months Ended June 30, 2017

Production taxes, transportation and processing. Our production taxes, transportation and processing expenses increased $13.2 million to $37.9 million, or 54%, for the six months ended June 30, 2018, as compared to $24.7 million for the six months ended June 30, 2017. On a unit-of-production basis, our production taxes, transportation and processing expenses increased 9% to $4.26 per BOE for the six months ended June 30, 2018, as compared to $3.90 per BOE for the six months ended June 30, 2017. The increase in production taxes, transportation and processing expenses was primarily attributable to the $14.1 million increase in our production taxes to $28.2 million for the six months ended June 30, 2018, as compared to $14.1 million for the six months ended June 30, 2017, principally due to the $162.4 million increase in oil and natural gas revenues for the six months ended June 30, 2018, as compared to the six months ended June 30, 2017. In addition, the production tax rates in New Mexico are higher than production tax rates in Texas. As more of our oil and natural gas production becomes attributable to New Mexico, we expect our production tax expenses to increase proportionately.

Lease operating. Our lease operating expenses increased $15.4 million to $47.2 million, or 48%, for the six months ended June 30, 2018, as compared to $31.8 million for the six months ended June 30, 2017. Our lease operating expenses on a unit-of production basis increased 6% to $5.30 per BOE for the six months ended June 30, 2018, as compared to $5.02 per BOE for the six months ended June 30, 2017. The increase in lease operating expenses for the six months ended June 30, 2018, as compared to the six months ended June 30, 2017, was primarily attributable to an increase in costs of services and equipment, including salt water disposal costs in asset areas other than Wolf and Rustler Breaks (which are serviced by San Mateo), at June 30, 2018, as compared to June 30, 2017.

Plant and other midstream services operating. Our plant and other midstream services operating expenses increased $4.6 million to $9.9 million, or 87%, for the six months ended June 30, 2018, as compared to $5.3 million for the six months ended June

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30, 2017. This increase was primarily attributable to (i) increased expenses associated with our expanded commercial salt water disposal operations to $5.2 million for the six months ended June 30, 2018, as compared to $3.0 million for the six months ended June 30, 2017 and (ii) increased expenses associated with the Black River Processing Plant to $3.6 million for the six months ended June 30, 2018, as compared to $1.8 million for the six months ended June 30, 2017.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses increased $46.9 million to $122.2 million, or 62%, for the six months ended June 30, 2018, as compared to $75.3 million for the six months ended June 30, 2017. On a unit-of-production basis, our depletion, depreciation and amortization expenses increased 16% to $13.74 per BOE for the six months ended June 30, 2018, as compared to $11.89 per BOE for the six months ended June 30, 2017. The increase in our total depletion, depreciation and amortization expenses was primarily attributable to (i) increased well costs, largely as a result of increased well stimulation costs in response to increased oil prices over the past year and (ii) the 40% increase in our total oil equivalent production to 8.9 million BOE for the six months ended June 30, 2018, as compared to 6.3 million BOE for the six months ended June 30, 2017. The impact of the increase in well costs and oil and natural gas production was partially offset by higher total proved oil and natural gas reserves at June 30, 2018, as compared to June 30, 2017, primarily attributable to our ongoing delineation and development drilling activities in the Delaware Basin. In addition, depreciation expenses attributable to our midstream segment were approximately $3.9 million for the six months ended June 30, 2018, as compared to $2.5 million for the six months ended June 30, 2017.

General and administrative. Our general and administrative expenses increased $3.8 million to $37.3 million, or 11%, for the six months ended June 30, 2018, as compared to $33.5 million for the six months ended June 30, 2017. The increase in our general and administrative expenses was partially attributable to increased payroll and related expenses of approximately $7.6 million associated with additional employees joining the Company to support our increased land, geoscience, drilling, completion, production, midstream, accounting and administration functions as a result of the continued growth of the Company. These increases were partially offset by the $3.3 million increase in capitalized general and administrative expenses for the six months ended June 30, 2018, as compared to the six months ended June 30, 2017. As a result of the 40% increase in oil and natural gas production for the six months ended June 30, 2018, as compared to the six months ended June 30, 2017, our general and administrative expenses decreased 21% on a unit-of-production basis to $4.19 per BOE for the six months ended June 30, 2018, as compared to $5.29 per BOE for the six months ended June 30, 2017.

Interest expense. For the six months ended June 30, 2018, we incurred total interest expense of approximately $21.0 million. We capitalized approximately $4.5 million of our interest expense on certain qualifying projects for the six months ended June 30, 2018 and expensed the remaining $16.5 million to operations. For the six months ended June 30, 2017, we incurred total interest expense of approximately $20.8 million. We capitalized approximately $3.2 million of our interest expense on certain qualifying projects for the six months ended June 30, 2017 and expensed the remaining $17.7 million to operations.

Total income tax benefit. Our deferred tax assets exceeded our deferred tax liabilities at June 30, 2018 due to the deferred tax amounts generated by the full-cost ceiling impairment charges recorded in prior periods. As a result, we established a valuation allowance against the deferred tax assets beginning in the third quarter of 2015. We retained a full valuation allowance at June 30, 2018 due to uncertainties regarding the future realization of our deferred tax assets.

Liquidity and Capital Resources

Our primary use of capital has been, and we expect will continue to be during the remainder of 2018 and for the foreseeable future, for the acquisition, exploration and development of oil and natural gas properties and for midstream investments. Excluding any possible significant acquisitions, we expect to fund our capital expenditure requirements for the remainder of 2018 through a combination of cash on hand (including proceeds from our May 2018 public equity offering), operating cash flows and borrowings under the Credit Agreement (assuming availability under our borrowing base). We continually evaluate other capital sources, including borrowings under additional credit arrangements, the sale or joint venture of midstream assets or oil and natural gas producing assets or acreage, particularly in our non-core asset areas, as well as potential issuances of equity, debt or convertible securities, none of which may be available on satisfactory terms or at all. Our future success in growing proved reserves and production will be highly dependent on our ability to access outside sources of capital and to generate operating cash flows.

At June 30, 2018, we had cash totaling approximately $122.5 million and restricted cash totaling approximately $21.1 million, most of which is associated with San Mateo. By contractual agreement, the cash in the accounts held by our less-than-wholly-owned subsidiaries is not to be commingled with our other cash and is to be used only to fund the capital expenditures and operations of these less-than-wholly-owned subsidiaries.

During the first quarter of 2018, the lenders under our Credit Agreement completed their review of the Company's proved oil and natural gas reserves at December 31, 2017, and as a result, on March 5, 2018, the borrowing base was increased to $725.0 million and the maximum facility amount remained at $500.0 million. This March 2018 redetermination constituted the regularly scheduled May 1 redetermination. The Company elected to keep the lenders' borrowing commitment at $400.0

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million. Borrowings under the Credit Agreement are limited to the lowest of the borrowing base, the maximum facility amount and the elected commitment. The Credit Agreement matures on October 16, 2020.

In April 2018, we accessed the line of credit under our Credit Agreement and borrowed $45.0 million to fund certain of our acreage and mineral acquisitions, as well as for our ongoing exploration and development and midstream activities and for general corporate purposes. On May 17, 2018, we completed a public offering of 7,000,000 shares of our common stock. After deducting offering costs totaling approximately $0.1 million, we received net proceeds of approximately $226.5 million. The proceeds from this offering were and are being used to acquire additional leasehold and mineral acres in the Delaware Basin, to fund certain midstream initiatives in the Delaware Basin and for general corporate purposes, including to fund a portion of the Company's future capital expenditures. Pending such uses, we used a portion of the proceeds from the offering to repay the $45.0 million of outstanding borrowings under our Credit Agreement and invested the remaining funds in short-term marketable securities. At June 30, 2018 and August 1, 2018, we had no borrowings outstanding under our Credit Agreement and approximately $3.0 million in outstanding letters of credit issued pursuant to the Credit Agreement.

We expect that development of our Delaware Basin assets will be the primary focus of our operations and capital expenditures for the remainder of 2018. We plan to operate six contracted drilling rigs in the Delaware Basin throughout the remainder of 2018. Depending on commodity prices and basis differentials, capital and operating costs, opportunities in asset areas like Arrowhead and Antelope Ridge, liquidity and other factors, we may consider adding a seventh rig during the fourth quarter of 2018, although we had not made the decision to do so at August 1, 2018. Should we elect to add a seventh drilling rig during the fourth quarter of 2018, we anticipate this additional rig will have no impact on our estimated 2018 oil and natural gas production and only a minor impact on our anticipated capital expenditures for the remainder of 2018.

As of August 1, 2018, we adjusted our anticipated capital expenditures for drilling and completions (including equipping wells for production) from $530 to $570 million to $620 to $650 million and our anticipated midstream capital expenditures remained $70 to $90 million, which represents our 51% share of San Mateo's 2018 estimated capital expenditures. During the second quarter of 2018, we incurred capital expenditures of approximately $166.1 million for drilling, completions, facilities and infrastructure and approximately $16.7 million for midstream activities, which primarily represented 51% of San Mateo's total second quarter capital expenditures of $32.7 million.

We have allocated substantially all of our estimated 2018 capital expenditures to the further delineation and development of our growing leasehold position and midstream assets in the Delaware Basin, with the exception of amounts allocated to limited operations in the Eagle Ford and Haynesville shales. For the remainder of 2018, our Delaware Basin drilling program will continue to focus on the development of the Wolf and Rustler Breaks asset areas and the further delineation and development of the Jackson Trust, Ranger/Arrowhead, Antelope Ridge and Twin Lakes asset areas, although we may also continue to delineate previously untested zones in the Wolf and Rustler Breaks asset areas.

From January 1 through August 1, 2018, we acquired or had under contract approximately 16,000 net leasehold and mineral acres in and around our existing acreage positions in the Delaware Basin, including approximately 3,400 net mineral acres. From January 1 through August 1, 2018, we had incurred net capital expenditures of approximately $155 million to acquire approximately 9,500 net acres of these leasehold and mineral interests. We expect to incur net capital expenditures of approximately $32 million to acquire the additional approximately 6,500 net acres in leasehold and mineral interests that were under contract as of August 1, 2018 during the third and fourth quarters of 2018; the purchase price for such additional acquisitions is expected to be funded with a portion of the proceeds of our May 2018 equity offering. We intend to continue acquiring acreage and mineral interests, principally in the Delaware Basin, during the remainder of 2018. These expenditures are opportunity-specific and per-acre prices can vary significantly based on the prospect. As a result, it is difficult to estimate these remaining 2018 capital expenditures with any degree of certainty; therefore, we have not provided estimated capital expenditures related to acreage and mineral acquisitions for the remainder of 2018.

Our 2018 capital expenditures may be adjusted as business conditions warrant and the amount, timing and allocation of such expenditures is largely discretionary and within our control. The aggregate amount of capital we will expend may fluctuate materially based on market conditions, the actual costs to drill, complete and place on production operated or non-operated wells, our drilling results, the actual costs and scope of our midstream activities, the ability of our joint venture partners to meet their capital obligations, other opportunities that may become available to us and our ability to obtain capital. When oil or natural gas prices decline, or costs increase significantly, we have the flexibility to defer a significant portion of our capital expenditures until later periods to conserve cash or to focus on projects that we believe have the highest expected returns and potential to generate near-term cash flows. We routinely monitor and adjust our capital expenditures in response to changes in prices, availability of financing, drilling, completion and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, success or lack of success in our exploration and development activities, contractual obligations, drilling plans for properties we do not operate and other factors both within and outside our control.

Exploration and development activities are subject to a number of risks and uncertainties, which could cause these activities to be less successful than we anticipate. A significant portion of our anticipated cash flows from operations for the

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remainder of 2018 is expected to come from producing wells and development activities on currently proved properties in the Wolfcamp and Bone Spring plays in the Delaware Basin, the Eagle Ford shale in South Texas and the Haynesville shale in Louisiana. Our existing wells may not produce at the levels we have forecasted and our exploration and development activities in these areas may not be as successful as we anticipate. Additionally, our anticipated cash flows from operations are based upon current expectations of realized oil, natural gas and NGL prices for the remainder of 2018 and the hedges we currently have in place. We use commodity derivative financial instruments at times to mitigate our exposure to fluctuations in oil, natural gas and NGL prices and to partially offset reductions in our cash flows from operations resulting from declines in commodity prices. See Note 7 to the interim unaudited condensed consolidated financial statements in this Quarterly Report for a summary of our open derivative financial instruments at June 30, 2018.

Our unaudited cash flows for the six months ended June 30, 2018 and 2017 are presented below:

	Six Months Ended June 30,	
(In thousands)	2018	2017
Net cash provided by operating activities	$254,208	$121,242
Net cash used in investing activities	(493,562)	(369,695)
Net cash provided by financing activities	280,385	180,818
Net change in cash and restricted cash	$41,031	$(67,635)
Adjusted EBITDA attributable to Matador Resources Company shareholders[(1)]	$254,592	$142,611

(1) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see "— Non-GAAP Financial Measures" below.

Cash Flows Provided by Operating Activities

Net cash provided by operating activities increased $133.0 million to $254.2 million for the six months ended June 30, 2018 from $121.2 million for the six months ended June 30, 2017. Excluding changes in operating assets and liabilities, net cash provided by operating activities increased to $251.0 million for the six months ended June 30, 2018 from $130.9 million for the six months ended June 30, 2017. This increase was primarily attributable to higher oil and natural gas production and higher oil prices. Changes in our operating assets and liabilities between the two periods resulted in a net increase of approximately $12.8 million in net cash provided by operating activities for the six months ended June 30, 2018, as compared to the six months ended June 30, 2017.

Our operating cash flows are sensitive to a number of variables, including changes in our production and volatility of oil and natural gas prices between reporting periods. Regional and worldwide economic activity, the actions of OPEC, weather, infrastructure capacity to reach markets and other variable factors significantly impact the prices of oil and natural gas. These factors are beyond our control and are difficult to predict. We use commodity derivative financial instruments to mitigate our exposure to fluctuations in oil, natural gas and NGL prices. In addition, we attempt to avoid long-term service agreements where possible in order to minimize ongoing future commitments.

Cash Flows Used in Investing Activities

Net cash used in investing activities increased by $123.9 million to $493.6 million for the six months ended June 30, 2018 from $369.7 million for the six months ended June 30, 2017. This increase in net cash used in investing activities is primarily due to an increase of $92.7 million in oil and natural gas properties capital expenditures for the six months ended June 30, 2018, as compared to the six months ended June 30, 2017. Cash used for oil and natural gas properties capital expenditures for the six months ended June 30, 2018 was primarily attributable to the acquisition of additional leasehold and mineral interests and to our operated and non-operated drilling and completion activities in the Delaware Basin. The remaining increase was attributable to an increase in cash used for midstream and other property and equipment of $37.8 million primarily related to capital expenditures for San Mateo, which was partially offset by a net increase of $6.6 million in proceeds from the sale of acreage.

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Cash Flows Provided by Financing Activities

Net cash provided by financing activities increased by $99.6 million to $280.4 million for the six months ended June 30, 2018 from $180.8 million for the six months ended June 30, 2017. During the six months ended June 30, 2018, we received net proceeds of $226.5 million from our May 2018 public equity offering, as well as an increase of $39.2 million in contributions from non-controlling interest owners in less-than-wholly-owned subsidiaries. These increases were offset by a decrease of $156.8 million in contributions related to the formation of San Mateo in 2017 as well as an increase of $8.6 million in distributions to non-controlling interest owners in less-than-wholly-owned subsidiaries.

Non-GAAP Financial Measures

We define Adjusted EBITDA as earnings before interest expense, income taxes, depletion, depreciation and amortization, accretion of asset retirement obligations, property impairments, unrealized derivative gains and losses, certain other non-cash items and non-cash stock-based compensation expense, and net gain or loss on asset sales and inventory impairment. Adjusted EBITDA is not a measure of net income (loss) or cash flows as determined by GAAP. Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of our consolidated financial statements, such as industry analysts, investors, lenders and rating agencies. Management believes Adjusted EBITDA is necessary because it allows us to evaluate our operating performance and compare the results of operations from period to period without regard to our financing methods or capital structure. We exclude the items listed above from net income (loss) in calculating Adjusted EBITDA because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which certain assets were acquired.

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income (loss) or cash flows from operating activities as determined in accordance with GAAP or as a primary indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDA are significant components of understanding and assessing a company’s financial performance, such as a company’s cost of capital and tax structure. Our Adjusted EBITDA may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDA in the same manner.

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The following table presents our calculation of Adjusted EBITDA and the reconciliation of Adjusted EBITDA to the GAAP financial measures of net income and net cash provided by operating activities, respectively.

	Three Months Ended June 30,		Six Months Ended June 30,	
(In thousands)	2018	2017	2018	2017
Unaudited Adjusted EBITDA Reconciliation to Net Income:				
Net income attributable to Matador Resources Company shareholders	$59,806	$28,509	$119,700	$72,493
Net income attributable to non-controlling interest in subsidiaries	5,831	3,178	10,861	5,094
Net income	65,637	31,687	130,561	77,587
Interest expense	8,004	9,224	16,495	17,679
Depletion, depreciation and amortization	66,838	41,274	122,207	75,266
Accretion of asset retirement obligations	375	314	739	614
Unrealized gain on derivatives	(1,429)	(13,190)	(11,845)	(33,821)
Stock-based compensation expense	4,766	7,026	8,945	11,192
Net gain on asset sales and inventory impairment	—	—	—	(7)
Consolidated Adjusted EBITDA	144,191	76,335	267,102	148,510
Adjusted EBITDA attributable to non-controlling interest in subsidiaries	(6,853)	(3,683)	(12,510)	(5,899)
Adjusted EBITDA attributable to Matador Resources Company shareholders	$137,338	$72,652	$254,592	$142,611

	Three Months Ended June 30,		Six Months Ended June 30,	
(In thousands)	2018	2017	2018	2017
Unaudited Adjusted EBITDA Reconciliation to Net Cash Provided by Operating Activities:				
Net cash provided by operating activities	$118,059	$59,933	$254,208	$121,242
Net change in operating assets and liabilities	18,174	7,198	(3,190)	9,653
Interest expense, net of non-cash portion	7,958	9,204	16,084	17,615
Adjusted EBITDA attributable to non-controlling interest in subsidiaries	(6,853)	(3,683)	(12,510)	(5,899)
Adjusted EBITDA attributable to Matador Resources Company shareholders	$137,338	$72,652	$254,592	$142,611

Net income attributable to Matador Resources Company shareholders increased by $31.3 million to $59.8 million for the three months ended June 30, 2018, as compared to $28.5 million for the three months ended June 30, 2017. This increase in net income attributable to Matador Resources Company shareholders for the three months ended June 30, 2018 as compared to the three months ended June 30, 2017 is primarily attributable to the increase in oil and natural gas revenues of $95.3 million, partially offset by an $11.8 million decrease in unrealized gain on derivatives and a $46.8 million increase in total expenses.

Net income attributable to Matador Resources Company shareholders increased by $47.2 million to $119.7 million for the six months ended June 30, 2018, as compared to $72.5 million for the six months ended June 30, 2017. This increase in net income attributable to Matador Resources Company shareholders for the six months ended June 30, 2018 as compared to the six months ended June 30, 2017 is primarily attributable to the increase in oil and natural gas revenues of $162.4 million, partially offset by a $22.0 million decrease in unrealized gain on derivatives and an $84.0 million increase in total expenses.

Adjusted EBITDA, a non-GAAP financial measure, increased by $64.7 million to $137.3 million for the three months ended June 30, 2018, as compared to $72.7 million for the three months ended June 30, 2017. This increase in our Adjusted EBITDA is primarily attributable to higher oil and natural gas production and higher oil prices for the three months ended June 30, 2018, as compared to the three months ended June 30, 2017.

Adjusted EBITDA, a non-GAAP financial measure, increased by $112.0 million to $254.6 million for the six months ended June 30, 2018, as compared to $142.6 million for the six months ended June 30, 2017. This increase in our Adjusted EBITDA is primarily attributable to higher oil and natural gas production and higher oil prices for the six months ended June 30, 2018, as compared to the six months ended June 30, 2017.

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Off-Balance Sheet Arrangements

From time-to-time, we enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of June 30, 2018, the material off-balance sheet arrangements and transactions that we have entered into include (i) operating lease agreements, (ii) non-operated drilling commitments, (iii) termination obligations under drilling rig contracts, (iv) firm transportation, gathering, processing and disposal commitments and (v) contractual obligations for which the ultimate settlement amounts are not fixed and determinable, such as derivative contracts that are sensitive to future changes in commodity prices or interest rates, gathering, treating, transportation and disposal commitments on uncertain volumes of future throughput, open delivery commitments and indemnification obligations following certain divestitures. Other than the off-balance sheet arrangements described above, the Company has no transactions, arrangements or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect the Company's liquidity or availability of or requirements for capital resources. See "— Obligations and Commitments" below and Note 9 to the interim unaudited condensed consolidated financial statements in this Quarterly Report for more information regarding our off-balance sheet arrangements. Such information is incorporated herein by reference.

Obligations and Commitments

We had the following material contractual obligations and commitments at June 30, 2018:

	Payments Due by Period				
(In thousands)	Total	Less Than 1 Year	1 - 3 Years	3 - 5 Years	More Than 5 Years
Contractual Obligations:					
Revolving credit borrowings, including letters of credit(1)	$2,991	$—	$—	$2,991	$—
Senior unsecured notes(2)	575,000	—	—	575,000	—
Office leases	21,370	2,490	5,215	5,548	8,117
Non-operated drilling commitments(3)	47,190	47,190	—	—	—
Drilling rig contracts(4)	32,439	29,547	2,892	—	—
Asset retirement obligations	28,125	1,235	871	2,026	23,993
Natural gas transportation, gathering and processing agreements with non-affiliates(5)	451,087	8,479	86,559	90,815	265,234
Gathering, processing and disposal agreements with San Mateo(6)	222,614	2,313	69,994	75,102	75,205
Natural gas construction contracts(7)	15,474	15,474	—	—	—
Total contractual cash obligations	$1,396,290	$106,728	$165,531	$751,482	$372,549

(1) At June 30, 2018, we had no borrowings outstanding under our Credit Agreement and approximately $3.0 million in outstanding letters of credit issued pursuant to the Credit Agreement. The Credit Agreement matures in October 2020.

(2) The amounts included in the table above represent principal maturities only. Interest expense on our 6.875% senior notes due 2023 that are outstanding as of June 30, 2018 is expected to be approximately $39.5 million each year until maturity.

(3) At June 30, 2018, we had outstanding commitments to participate in the drilling and completion of various non-operated wells. Our working interests in these wells are typically small, and certain of these wells were in progress at June 30, 2018. If all of these wells are drilled and completed, we will have minimum outstanding aggregate commitments for our participation in these wells of approximately $47.2 million at June 30, 2018, which we expect to incur within the next year.

(4) We do not own or operate our own drilling rigs, but instead enter into contracts with third parties for such drilling rigs. See Note 9 to the interim unaudited condensed consolidated financial statements in this Quarterly Report for more information regarding these contractual commitments.

(5)

In late 2015, we entered into a 15-year fixed-fee natural gas gathering and processing agreement for a significant portion of our operated natural gas production in Loving County, Texas. In late 2017, we entered into an 18-year fixed-fee natural gas transportation agreement where we committed to deliver a portion of the residue natural gas production at the tailgate of the Black River Processing Plant to transport through the counterparty's pipeline in Eddy County, New Mexico. In late 2017, we also entered into a fixed-fee NGL transportation and fractionation agreement whereby we committed to deliver our NGL production at the tailgate of the Black River Processing Plant. We have committed to deliver a minimum amount of NGLs to the counterparty upon construction and completion of a pipeline expansion and a fractionation facility by the counterparty, which is currently expected to be completed late in 2019. We have no rights to compel the counterparty to construct this pipeline extension or fractionation facility. If the counterparty does not construct the pipeline extension and fractionation facility, then we do not have any minimum volume commitments under the agreement. If the counterparty constructs the pipeline extension and fractionation facility on or prior to February 28, 2021, then we will have a commitment to deliver a minimum amount of NGLs for seven years following the completion of the pipeline extension and fractionation facility. If we do not meet our NGL volume commitment in any quarter during the seven-year commitment period, we will be required to pay a deficiency fee per gallon of NGL deficiency. The amounts in the table assume that the seven-year period containing minimum NGL volume commitments begins in late 2019. In the second quarter of 2018, we entered into a 16-year, fixed fee natural gas transportation agreement that begins on October 1, 2019, whereby we committed to deliver a portion

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of the residue natural gas production at the tailgate of the Black River Processing Plant to transport through the counterparty's pipeline. Additionally, in the second quarter of 2018, we entered into a short-term natural gas transportation agreement whereby we committed to deliver a portion of the residue natural gas production at the tailgate of the Black River Processing Plant to transport through the counterparty's pipeline. Lastly, in the second quarter of 2018, we entered into a 10-year, fixed-fee natural gas sales agreement whereby we committed to deliver residue natural gas through the counterparty's pipeline to the Texas Gulf Coast beginning on the in-service date for such pipeline, which is expected to be operational in late 2019. See Note 9 to the interim unaudited condensed consolidated financial statements in this Quarterly Report for more information regarding these contractual commitments.

(6) In February 2017, we dedicated our current and future leasehold interests in the Rustler Breaks and Wolf asset areas pursuant to 15-year, fixed-fee natural gas, oil and salt water gathering agreements and salt water disposal agreements. In addition, effective February 1, 2017, we dedicated our current and future leasehold interests in the Rustler Breaks asset area pursuant to a 15-year, fixed-fee natural gas processing agreement. See Note 9 to the interim unaudited condensed consolidated financial statements in this Quarterly Report for more information regarding these contractual commitments.

(7) Beginning in May 2017, a subsidiary of San Mateo entered into certain agreements with third parties for the engineering, procurement, construction and installation of an expansion of the Black River Processing Plant. In addition, during the first quarter of 2018, a subsidiary of San Mateo entered into agreements for additional field compression and an amine gas treatment unit to maximize the operation of the Black River Processing Plant. See Note 9 to the interim unaudited condensed consolidated financial statements in this Quarterly Report for more information regarding these contractual commitments.

General Outlook and Trends

For the three months ended June 30, 2018, oil prices averaged $67.91 per Bbl, ranging from a high of $74.15 per Bbl in late June to a low of $62.06 per Bbl in early April, based upon the NYMEX West Texas Intermediate oil futures contract price for the earliest delivery date. We realized a weighted average oil price of $61.44 per Bbl ($60.52 per Bbl including realized losses from oil derivatives) for our oil production for the three months ended June 30, 2018, as compared to $46.01 per Bbl ($46.34 per Bbl including realized gains from oil derivatives) for our production for the three months ended June 30, 2017. At August 1, 2018, the NYMEX West Texas Intermediate oil futures contract for the earliest delivery date had remained essentially unchanged from the average price for the second quarter of 2018, settling at $67.66 per Bbl, which was a significant increase as compared to $49.16 per Bbl at August 1, 2017.

For the three months ended June 30, 2018, natural gas prices averaged $2.83 per MMBtu, ranging from a high of approximately $3.02 per MMBtu in mid-June to a low of approximately $2.66 per MMBtu in mid-April, based upon the NYMEX Henry Hub natural gas futures contract price for the earliest delivery date. We realized a weighted average natural gas price of $3.38 per Mcf (with essentially no realized gains or losses from natural gas derivatives) for our natural gas production (including revenues attributable to NGLs) for the three months ended June 30, 2018, as compared to $3.40 per Mcf ($3.39 per Mcf, including realized losses from natural gas derivatives) for our natural gas production (including revenues attributable to NGLs) for the three months ended June 30, 2017. At August 1, 2018, the NYMEX Henry Hub natural gas futures contract for the earliest delivery date had slightly decreased from the average price for the second quarter of 2018, settling at $2.76 per MMBtu, which was also a slight decrease as compared to $2.82 per MMBtu at August 1, 2017.

The prices we receive for oil, natural gas and NGLs heavily influence our revenue, profitability, cash flow available for capital expenditures, access to capital and future rate of growth. Oil, natural gas and NGLs are commodities, and therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil, natural gas and NGLs have been volatile and these markets will likely continue to be volatile in the future. Declines in oil, natural gas or NGL prices not only reduce our revenues, but could also reduce the amount of oil, natural gas and NGLs we can produce economically. We are uncertain if oil and natural gas prices may rise from their current levels, and in fact, oil and natural gas prices may decrease in future periods.

From time to time, we use derivative financial instruments to mitigate our exposure to commodity price risk associated with oil, natural gas and NGL prices and basis differentials. Even so, decisions as to whether, at what price and what production volumes to hedge are difficult and depend on market conditions and our forecast of future production and oil, natural gas and NGL prices, and we may not always employ the optimal hedging strategy. This, in turn, may affect the liquidity that can be accessed through the borrowing base under our Credit Agreement and through the capital markets.

In addition, the prices we receive for our oil and natural gas production often reflect a discount to the relevant benchmark prices, such as the NYMEX West Texas Intermediate oil price or the NYMEX Henry Hub natural gas price. The difference between these benchmark prices and the price we receive is called a differential. At June 30, 2018, most of our oil production from the Delaware Basin was sold based on prices established in Midland, Texas and most of our natural gas production from the Delaware Basin was sold based on prices established at the Waha Hub in far West Texas. During the first quarter of 2018, the price differentials for oil sold in Midland and natural gas sold at the Waha Hub compared to the benchmark prices for oil and natural gas, respectively, began to widen significantly, and these differentials widened further in the second quarter. These widening differentials negatively impacted our oil and natural gas revenues in the second quarter of 2018, especially in the latter portion of the quarter. These differentials, particularly for oil, have continued to widen since June 30, 2018 and are expected to further negatively impact our oil and natural gas revenues in the third quarter of 2018.

In early August 2018, these price differentials were approximately ($16.00) per barrel for oil and ($1.00) per MMBtu for natural gas. We anticipate that these widening price differentials could persist for 12 to 18 months or longer until additional oil

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and natural gas pipeline capacity from West Texas to the Texas Gulf Coast and other end markets is completed; however, we can provide no assurances as to how long these widening differentials may persist and, in fact, these price differentials could widen further in future periods. At June 30, 2018, we had approximately 50% of our anticipated Delaware Basin oil production for the second half of 2018 hedged at a weighted average basis differential swap price of ($1.02) per barrel to help mitigate our exposure to these widening oil basis differentials. See Note 7 to the interim unaudited condensed consolidated financial statements in this Quarterly Report for a summary of these oil basis swaps. At June 30, 2018, we had no hedges in place to mitigate our exposure to basis differentials for our natural gas production in 2018 and no basis hedges in place for either oil or natural gas in 2019 or beyond.

These widening basis differentials are largely attributable to industry concerns regarding the near-term sufficiency of pipeline takeaway capacity for oil, natural gas and NGL production in the Delaware Basin. At August 1, 2018, we had not experienced any pipeline-related interruptions to our oil, natural gas or NGL production during 2018. If we do experience any such interruptions, our oil and natural gas revenues, business, financial condition, results of operations and cash flows could be adversely affected.

Coinciding with the improvements in oil and natural gas prices since the latter part of 2016, we have experienced price increases from certain of our service providers for some of the products and services we use in our drilling, completion and production operations. If oil and natural gas prices remain at their current levels or increase further, we could experience additional price increases for drilling, completion and production products and services, although we can provide no estimates as to the eventual magnitude of these increases.

Our properties are subject to natural production declines. By their nature, our oil and natural gas wells experience rapid initial production declines. We attempt to overcome these production declines by drilling to develop and identify additional reserves, by exploring for new sources of reserves and, at times, by acquisitions. During times of severe oil, natural gas and NGL price declines, however, drilling certain oil or natural gas wells may not be economic, and we may find it necessary to reduce capital expenditures and curtail drilling operations in order to preserve liquidity. A material reduction in capital expenditures and drilling activities could materially impact our production volumes, revenues, reserves, cash flows and our availability under our Credit Agreement.

We strive to focus our efforts on increasing oil and natural gas reserves and production while controlling costs at a level that is appropriate for long-term operations. Our ability to find and develop sufficient quantities of oil and natural gas reserves at economical costs is critical to our long-term success. Future finding and development costs are subject to changes in the costs of acquiring, drilling and completing our prospects.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Except as set forth below, there have been no material changes to the sources and effects of our market risk since December 31, 2017, which are disclosed in Part II, Item 7A of the Annual Report and incorporated herein by reference.

Commodity price exposure. We are exposed to market risk as the prices of oil, natural gas and NGLs fluctuate as a result of changes in supply and demand and other factors. To partially reduce price risk caused by these market fluctuations, we have entered into derivative financial instruments in the past and expect to enter into derivative financial instruments in the future to cover a significant portion of our anticipated future production.

We typically use costless (or zero-cost) collars and/or swap contracts to manage risks related to changes in oil, natural gas and NGL prices. Traditional costless collars provide us with downside price protection through the purchase of a put option that is financed through the sale of a call option. Because the call option proceeds are used to offset the cost of the put option, these arrangements are initially “costless” to us. Participating three-way costless collars also provide the Company with downside price protection through the purchase of a put option, but they also allow the Company to participate in price upside through the purchase of a call option; the purchase of both the put option and the call option are financed through the sale of a call option. Because the proceeds from the call option sale are used to offset the cost of the purchased put and call options, these arrangements are also initially “costless” to the Company. In the case of a costless collar, the put option and the call option or options have different fixed price components. In a swap contract, a floating price is exchanged for a fixed price over a specified period, providing downside price protection.

We record all derivative financial instruments at fair value. The fair value of our derivative financial instruments is determined using purchase and sale information available for similarly traded securities. At June 30, 2018, RBC, The

Bank of Nova Scotia, BMO Harris Financing (Bank of Montreal) and SunTrust Bank (or affiliates thereof) were the counterparties for all of our derivative instruments. We have considered the credit standing of the counterparties in determining the fair value of our derivative financial instruments. See Note 7 to the interim unaudited condensed consolidated financial statements in this Quarterly Report for a summary of our open derivative financial instruments at June 30, 2018. Such information is incorporated herein by reference.

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Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this Quarterly Report, we evaluated the effectiveness of the design and operation of the Company’s disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer. Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that the Company’s disclosure controls and procedures were effective as of June 30, 2018 to ensure that (i) information required to be disclosed in the reports it files and submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms and that (ii) information required to be disclosed under the Exchange Act is accumulated and communicated to the Company’s management, including our Chief Executive Officer and our Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

There were no changes in our internal controls during the three months ended June 30, 2018 that have materially affected or are reasonably likely to have a material effect on our internal control over financial reporting.

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Part II — OTHER INFORMATION

Item 1. Legal Proceedings

We are party to several lawsuits encountered in the ordinary course of business. While the ultimate outcome and impact to us cannot be predicted with certainty, in the opinion of management, it is remote that these lawsuits will have a material adverse impact on our financial condition, results of operations or cash flows.

Item 1A. Risk Factors

We are subject to various risks and uncertainties in the course of our business. For a discussion of such risks and uncertainties, please see "Item 1A. Risk Factors" in the Annual Report.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

During the quarter ended June 30, 2018, the Company re-acquired shares of common stock from certain employees in order to satisfy the employees' tax liability in connection with the vesting of restricted stock.

Period	Total Number of Shares Purchased(1)	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased under the Plans or Programs
April 1, 2018 to April 30, 2018	5,971	$ 31.28	—	—
May 1, 2018 to May 31, 2018	673	30.56	—	—
June 1, 2018 to June 30, 2018	439	27.29	—	—
Total	7,083	$ 30.97	—	—

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(1) The shares were not re-acquired pursuant to any repurchase plan or program.

Item 5. Other Information

Effective August 1, 2018, the Company entered into a First Amendment (the "Goodwin Amendment") to that certain Employment Agreement with Billy E. Goodwin, Executive Vice President and Head of Operations, effective February 19, 2016 (the "2016 Agreement"). In connection with Mr. Goodwin's promotion to his current position, the Goodwin Amendment increases the payment Mr. Goodwin would receive upon termination for certain specified reasons, including by the Company other than for "just cause" or by Mr. Goodwin for "good reason," to an amount equal to one and one half times his then-current salary plus an amount equal to one and one half times the average of his annual bonuses with respect to the prior two years. In connection with termination by the Company without "just cause" or by Mr. Goodwin with "good reason" in contemplation of or following a "change in control," the Amendment increases the payment Mr. Goodwin would receive to an amount equal to three times his then-current base salary plus an amount equal to three times the average of his annual bonuses with respect to the prior two years. The Goodwin Amendment also lengthens the restricted period of the non-compete and non-solicit provisions of the 2016 Agreement to 24 months. The description of the Goodwin Amendment set forth above is qualified in its entirety by reference to the terms of the Goodwin Amendment, a copy of which is filed as Exhibit 10.1 to this Quarterly Report and is incorporated herein by reference.

Effective August 1, 2018, the Company entered into an Amended and Restated Employment Agreement (the "Robinson Amendment") with Bradley M. Robinson, Executive Vice President - Reservoir Engineering and Chief Technology Officer. The Robinson Amendment amends and restates the prior Employment Agreement between the Company and Mr. Robinson dated August 9, 2011, as amended to date (as amended, the "2011 Agreement"). In connection with Mr. Robinson's promotion to his current position, the Robinson Amendment makes the same changes to the 2011 Agreement as are described above with respect to the Goodwin Amendment for termination of employment without "just cause" or for "good reason," including following a "change in control."

As the Company has done for any employment agreements for executive officers entered into since 2014, the Robinson Amendment includes a “double trigger” change in control provision such that in contemplation of or following a “change in control,” if the Company terminates Mr. Robinson without “just cause” or he terminates his employment with “good reason,” the Company will pay the same amounts described above with respect to the Goodwin Amendment. In addition, among other changes, the Robinson Amendment expands the definition of “just cause” to the definition substantially set forth in the Company’s Proxy Statement for the Annual Meeting of Shareholders held on June 7, 2018 filed on April 26, 2018 (the “Proxy Statement”) and incorporated herein by reference.

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The description of the Robinson Amendment set forth above is qualified in its entirety by reference to the terms of the Robinson Amendment, a copy of which is filed as Exhibit 10.2 to this Quarterly Report and is incorporated herein by reference.

All references to “just cause,” “good reason” and “change in control” in this Item 5 shall have the meanings substantially as set forth in the Proxy Statement and incorporated herein by reference.

Item 6. Exhibits

Exhibit Number	Description
3.1	Certificate of Merger between Matador Resources Company (now known as MRC Energy Company) and Matador Merger Co. (incorporated by reference to Exhibit 3.4 to the Registration Statement on Form S-1 filed on August 12, 2011).
3.2	Amended and Restated Certificate of Formation of Matador Resources Company (incorporated by reference to Exhibit 3.2 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2017).
3.3	Certificate of Amendment to the Amended and Restated Certificate of Formation of Matador Resources Company dated April 2, 2015 (incorporated by reference to Exhibit 3.3 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2017).
3.4	Certificate of Amendment to the Amended and Restated Certificate of Formation of Matador Resources Company effective June 2, 2017 (incorporated by reference to Exhibit 3.4 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2017).
3.5	Amended and Restated Bylaws of Matador Resources Company, as amended (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed on February 22, 2018).
10.1	First Amendment to the Employment Agreement between Matador Resources Company and Billy E. Goodwin (filed herewith).
10.2	Amended and Restated Employment Agreement between Matador Resources Company and Bradley M. Robinson (filed herewith).
23.1	Consent of Netherland, Sewell & Associates, Inc. (filed herewith).
31.1	Certification of Principal Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
31.2	Certification of Principal Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
32.1	Certification of Principal Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).
32.2	Certification of Principal Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).
99.1	Audit report of Netherland, Sewell & Associates, Inc. (filed herewith).

101	The following financial information from Matador Resources Company’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2018 formatted in XBRL (eXtensible Business Reporting Language): (i) the Condensed Consolidated Balance Sheets - Unaudited, (ii) the Condensed Consolidated Statements of Operations - Unaudited, (iii) the Condensed Consolidated Statement of Changes in Shareholders’ Equity - Unaudited, (iv) the Condensed Consolidated Statements of Cash Flows - Unaudited and (v) the Notes to Condensed Consolidated Financial Statements - Unaudited (submitted electronically herewith).

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

	MATADOR RESOURCES COMPANY
Date: August 3, 2018 By:	/s/ Joseph Wm. Foran
	Joseph Wm. Foran
	Chairman and Chief Executive Officer
Date: August 3, 2018 By:	/s/ David E. Lancaster
	David E. Lancaster
	Executive Vice President and Chief Financial Officer